STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219 In the Matter of Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-2, SUB 1193 In the Matter of Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	)	ORDER ACCEPTING STIPULATIONS, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Thursday, February 27, 2020, at 7:00 p.m., in the Jury Assembly Room, 3rd Floor, Richmond County Judicial Center, 105 West Franklin Street, Rockingham, North Carolina

Monday, March 2, 2020, at 7:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, March 3, 2020, at 7:00 p.m., in the New Hanover County Courthouse, Courtroom 317, 316 Princess Street, Wilmington, North Carolina

Wednesday, March 4, 2020, at 7:00 p.m., in the Greene County Courthouse, 301 North Greene Street, Snow Hill, North Carolina

Thursday, March 12, 2020, at 7:00 p.m., in Courtroom 1A, Buncombe County Court, 60 Court Plaza, Asheville, North Carolina

Monday, August 24, 2020, at 2:00 p.m., held via video conference and reconvened on Tuesday, September 29, 2020, at 9:00 a.m., via video conference

BEFORE Commissioner Daniel G. Clodfelter, Presiding; Chair Charlotte A. Mitchell; and Commissioners ToNola D. Brown-Bland; Lyons Gray; Kimberly W. Duffley; Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

APPEARANCES

For Duke Energy Carolinas, LLC:

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For Carolina Industrial Group for Fair Utility Rates II (CIGFUR):

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For Carolina Utility Customers Association, Inc. (CUCA):[1]

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For the Commercial Group:

Alan R. Jenkins, Jenkins at Law, LLC, 2950 Yellowtail Avenue, Marathon, Florida 33050

[1] On January 12, 2021, the Commission issued an Order granting the motion of Mr. Page, and Marcus W. Trathen and Craig D. Schauer — of Brooks, Pierce, McLendon, Humphrey & Leonard, LLP — to allow Mr. Page to withdraw and to substitute Mr. Trathen and Mr. Schauer as counsel for CUCA.

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For Harris Teeter LLC:

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For Hornwood Inc. (Hornwood):

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For North Carolina Sustainable Energy Association (NCSEA):

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North Carolina Clean Energy Business Alliance (NCCEBA):

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For North Carolina Justice Center (NCJC), North Carolina Housing Coalition (NCHC), Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE) (collectively, NCJC et al.):

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For North Carolina League of Municipalities (NCLM):

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For the Sierra Club:

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For Vote Solar:[2]

Thadeus B. Culley, Regulatory Counsel, Senior Regional Director, 1911 Ephesus Church Road, Chapel Hill, North Carolina 27517

For the United States Department of Defense and All Other Federal Executive Agencies (Dept. of Defense):

Emily W. Medlyn, U.S. Army Legal Services Agency, ELD Division, Suite 4300, 9275 Gunston Road, Fort Belvoir, Virginia 22060

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For the Using and Consuming Public:

Dianna W. Downey, Chief Counsel; and Elizabeth D. Culpepper, Layla Cummings, Tim R. Dodge, Lucy E. Edmondson, William E. Grantmyre, Gina C. Holt, Megan Jost, John D. Little, and Nadia L. Luhr, Staff Attorneys, Public Staff–North Carolina Utilities Commission (Public Staff), 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

Teresa Townsend, Special Deputy Attorney General, and Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27603

[2] On February 22, 2021, the Commission issued an Order granting the motion of Mr. Culley and Harry Carl Johnson to allow Mr. Culley to withdraw and to substitute Mr. Johnson as counsel for Vote Solar.

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BY THE COMMISSION: On September 30, 2019, pursuant to Commission Rule R1-17(a), Duke Energy Progress, LLC (DEP or Company), filed notice of its intent to file a general rate case application.

On October 30, 2019, the Company filed its Application to Adjust Retail Rates and Request for an Accounting Order (the Application), along with a Rate Case Information Report Commission Form E-1 (Form E-1), and the direct testimony and exhibits of numerous witnesses.

PROCEDURAL HISTORY AND JURISDICTION

Procedural History

The Commission has issued a multitude of procedural orders in these dockets, all of which are a matter of record herein. The following is a summary of the most pertinent filings by DEP and the parties and the Commission's procedural orders.

On various dates, petitions to intervene were filed by the following parties and were granted by orders of the Commission: CIGFUR, CUCA, Commercial Group, FPWC, Harris Teeter, Hornwood, NC WARN, NCSEA, NCCEBA, NCJC et al., NCLM, Sierra Club, Vote Solar, and the Dept. of Defense. In addition, a Notice of Intervention was filed by the North Carolina Attorney General's Office (AGO). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19.

On November 14, 2019, the Commission issued its Order Establishing General Rate Case and Suspending Rates. On December 6, 2019, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice (Scheduling Order).

The expert witness hearing in this matter was initially set to commence on May 4, 2020. However, due to the novel coronavirus pandemic (COVID-19) and the State of Emergency declared by Governor Roy Cooper, on April 3, 2020, the Company filed a Motion for an Order Addressing Procedural Issues. As part of the motion, DEP acknowledged that one complicating factor was the potential running of the 270-day suspension period specified in the Commission's November 14, 2020 Order and the potential mandatory placement of DEP's proposed rates into effect under N.C.G.S. § 62-134(b). Therefore, subject to its right to implement temporary rates under N.C.G.S. § 62-135, DEP asked the Commission to issue an order acknowledging and accepting DEP's notice of the prospective waiver through December 31, 2020, of its right to seek to implement its original proposed rates in this proceeding by operation of N.C.G.S. § 62-134(b) in the event that the postponement sought rendered the issuance of a Commission determination on just and reasonable rates in this proceeding prior to the end of the suspension period infeasible.

In February and March 2020, the Commission held five public hearings as scheduled by the Scheduling Order for the purpose of receiving the testimony of public witnesses.

On April 7, 2020, the Commission issued its Order Addressing Procedural Matters providing for revised testimony filing deadlines and discovery guidelines for the Company's rebuttal testimony.

On April 13, 2020, the Public Staff and numerous other parties filed the direct testimony and exhibits of their witnesses. On April 23, 2020, the Public Staff filed the supplemental testimony of several witnesses.

On May 4, 2020, DEP filed the rebuttal testimony and exhibits of several witnesses.

On May 6, 2020, DEP, its affiliate Duke Energy Carolinas, LLC (DEC) (collectively the Companies), and the Public Staff filed a motion to consolidate for hearing DEP's Application and DEC's Application to Adjust Retail Rates and Request for an Accounting Order in Docket No. E-7, Sub 1214 (DEC Application). Their motion stated that many of the issues in the two rate cases were based on substantially similar testimony and that efficiencies could be gained by consolidating the expert witness hearings for the Companies.

On May 29, 2020, the Commission issued an Order Proposing Procedures for Partially Consolidated Expert Witness Hearing, Scheduling Pre-Hearing Conference. The order revised the schedule for the DEP expert witness hearing and consolidated the DEP hearing with the expert witness hearing in the DEC Application on topics to be later identified.

On June 2, 2020, DEP and the Public Staff entered into and filed an Agreement and Stipulation of Partial Settlement (First Partial Stipulation) settling some issues in the case. That same day, the Company filed settlement testimony of witness De May and settlement testimony and exhibits of witness Smith.

On June 5, 2020, a pre-hearing conference was held. By subsequent orders, the Commission scheduled a consolidated DEC and DEP expert witness hearing on several topics, with the hearing to be held remotely by video conference.

On June 8, 2020, DEP and Harris Teeter entered into and filed a Settlement Agreement (Harris Teeter Stipulation or HT Stipulation).

On June 9, 2020, DEP and the Commercial Group entered into and filed a Settlement Agreement (Commercial Group Stipulation or CG Stipulation).

On June 22, 2020, DEP filed a Petition for An Accounting Order to Defer Impacts of Its Suspended Rate Case In Lieu of Implementing Temporary Rates Under Bond requesting to defer the revenue impacts of the postponement of the expert witness hearing.

On June 26, 2020, DEP and CIGFUR entered into and filed an Agreement and Stipulation of Settlement (CIGFUR Stipulation).

On July 9, 2020, DEP filed an Agreement and Stipulation of Settlement with Vote Solar (Vote Solar Stipulation).

On July 10, 2020, the Commission issued an order denying DEP's Petition for Accounting Order.

On July 23, 2020, DEP, NCSEA, and NCJC et al. entered into and filed an Agreement and Stipulation of Settlement (NCSEA/NCJC et al. Stipulation).

On July 31, 2020, DEP and the Public Staff entered into and filed a Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation, collectively with the First Partial Stipulation, the Public Staff Partial Stipulations) settling additional issues in the case. That same day and in support of the Second Partial Stipulation, the Public Staff filed the testimony of witnesses Maness, McLawhorn, and Woolridge, and the Company filed the testimony of witnesses De May, D'Ascendis, Smith, and Newlin.

On various dates in August 2020, the Company filed amendments to the Commercial Group, Vote Solar, CIGFUR, Harris Teeter, and NCSEA/NCJC et al. Stipulations, whereby the parties agreed that if the Commission enters a final order in this docket approving a 9.60% ROE based on a 52% equity and 48% long-term debt capital structure then certain provisions of each of their respective stipulations would be deemed fulfilled.

On August 7, 2020, DEP filed its Motion for Approval of Notice Required by N.C.G.S. § 62-135 to Implement Temporary Rates, Subject to Refund, and Authorization of EDIT Riders and Motion for Approval of Undertaking Required by N.C.G.S. § 62-135 to Implement Temporary Rates, Subject to Refund.

On August 10, 2020, the Commission issued its Order Rescheduling Separate Expert Witness Hearings to be Conducted Remotely.

On August 11, 2020, the Commission entered an Order Consolidating Dockets, consolidating the rate case and the Company's Application for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego in Docket No. E-2, Sub 1193.

Also on August 11, 2020, the Commission issued its Order Approving Public Notice of Interim Rates Subject to Refund and Financial Undertaking.

On August 24, 2020, the matter came on for the consolidated expert witness hearing. Testimony and exhibits were presented for DEC, DEP, and several parties on financial issues, including cost of capital, capital structure and credit quality, as well as Excess Deferred Income Taxes (EDIT), the Companies' proposed Grid Improvement Plan, and rate affordability. The DEP-specific expert witness hearing commenced on September 29, 2020, and DEP and the parties presented testimony and exhibits on numerous additional issues specific to DEP.

On December 4, 2020, several parties submitted post-hearing briefs and proposed orders.

On January 25, 2021, DEP, DEC, the Public Staff, AGO, and Sierra Club (collectively, CCR Settling Parties) filed a Coal Combustion Residuals Settlement Agreement (CCR Settlement) in the instant dockets and in Docket Nos. E-2, Sub 1142, E-7, Sub 1146, and E-7, Sub 1214 (rate case dockets).

On January 29, 2021, CCR Settling Parties filed a joint motion requesting that the Commission reopen the rate case dockets, consolidate consideration of the CCR Settlement in the dockets with its further consideration of issues remanded to the Commission by the North Carolina Supreme Court in *State ex rel. Utils. Comm'n v. Stein,* 375 N.C. 870, 851 S.E.2d 237 (2020) (*Stein*), admit the CCR Settlement and supporting testimony into evidence, and approve the CCR Settlement, reflecting that approval in its decisions in the rate case dockets, as well as in its order(s) on remand in response to the *Stein* decision.

On February 1, 2021, DEC and DEP filed testimony and exhibits in support of the CCR Settlement, and on February 5, 2021, the Public Staff filed testimony and exhibits in support of the CCR Settlement.

On February 12, 2021, the Commission issued an order reopening the rate case dockets, accepting into evidence the CCR Settlement and supporting testimony, allowing parties to file testimony or comments on the CCR Settlement, and allowing parties to file a request for a hearing on the CCR Settlement and supporting testimony.

Jurisdiction

No party has contested the fact that DEP is a public utility subject to the Commission's jurisdiction pursuant to the Public Utilities Act (Act), Chapter 62 of the North Carolina General Statutes. The Commission concludes that it has personal jurisdiction over DEP and subject matter jurisdiction over the matters presented in DEP's Application.

Application

In summary, DEP requested in its Application and initial direct testimony and exhibits a base rate increase of approximately $585.9 million, or 15.6%, in its annual electric sales, offset by a rate reduction of $120.2 million to refund certain tax benefits and $2.1 million related to the proposed Regulatory Asset and Liability Rider, for a net revenue increase of $463.6 million, or 12.3% from its North Carolina retail electric operations, including an ROE of 10.30% and a capital structure consisting of 47% debt and 53% equity.

DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2018, adjusted for certain known changes in revenue, expenses, and rate base.

DEP, by its Second Settlement Testimony and Exhibits, revised its requested base revenue requirement increase to $408,933,000 to incorporate the Company's adjustments filed in its Second Settlement Testimony and Exhibits filing and the Company's Second Supplemental Testimony and Exhibits filing, offset by a rate increase of $7,381,000 for the Revised Annual EDIT Rider 1 and reduction of ($152,348,000) for the Annual EDIT Rider 2 to refund certain tax benefits, and ($2,091,000) for the Regulatory Asset and Liability Rider, for a net revenue increase of $261,875,000.

Whole Record

The Commission held public witness hearings as noted above. The following public witnesses appeared and testified:

Rockingham:	No public witnesses appeared.
Raleigh:	Joe Adamsky, Lib Hutchby, April Springer, Ananya Seelam, Christopher Thompson, Hwa Huang, Bob Rodriguez, Steve Hahn, Kay Reibold, Jean-Luc Duvall, Mary Black, Beverly Moriarty, Barbara Cain, Sarah Macleod Owens, Carolyn Guckert, and Eleanor Weston
Wilmington:	Herb Harton, George Vlasits, Clarice Reber, Beth Hansen, Jimmie Davis, Dwight Willis, Roberta Buckles, Shelli Sordellini, Priss Endo, Peter Perschbacher, Tim Holder, Deborah Dicks-Maxwell, Adair Wright, and Harper Peterson
Snow Hill:	Bobby Jones, Lorrine Washington, Antonio Blow, Kristiann Hering, and Benjamin Lanier
Asheville:	Roger Hollis, Viola Williams, Ben Scales, Stephanie Biziewski, Amanda Strawderman, Cody Kelly, Amanda Seta, Dr. Steven Norris, Cathy Holt, Jeff Jones, Phillip Bisesi, Padma Dyvine, David Saulsbury, Max Mandler, Sonny Charles Rawls, Chloe Moore, Judy Mattox, Ken Brame, Alex Lines, Melanie Noyes Debbie Resnick, Kim Roney, and Kenneth Bradley Lenz

In summary, almost all the public witnesses stated their opposition to DEP's proposed rate increase. *See generally*, tr. vols. 2-5. Many witnesses testified that they were on fixed incomes and about the poverty in some of the counties served by DEP. In addition, many public witnesses stated concerns about coal ash, including the health effects on people located in proximity to coal ash basins and contamination of water supplies. Further, witnesses expressed their view that it is unfair for the cost of the coal ash cleanup to burden ratepayers rather than coming out of the Company's or shareholders' profits. Moreover, public witnesses testified to their concern regarding DEP's use of fossil fuels, including coal and natural gas power plants, fracking, and DEP not adequately increasing the use of clean energy and renewables. Finally, some public witnesses voiced their view that DEP's executive compensation and shareholder dividends are excessive.

In addition to the public witness testimony, the Commission received numerous consumer statements of position, all of which were filed in the docket. *See generally*, Docket No. E-2, Sub 1219CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEP's rate case Application.

In the Scheduling Order the Commission, without objection from any party, took judicial notice pursuant to N.C.G.S. § 62-65 of all evidence, decisions and matters of record on the issues of coal ash remediation, Power Forward, and advanced metering infrastructure (AMI), in DEP's last general rate case in Docket No. E-2, Sub 1142 (Sub 1142).[1] Said evidence, decisions and matters of record are hereby accepted into evidence in the present docket and incorporated by reference into this Order. The judicially noticed evidence will not be repeated in full or summarized but portions of the testimony and exhibits are referenced throughout this Order.

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order. Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

[1] In referring to the evidence from the 2018 DEP rate case the Commission will designate the transcript and exhibits as "2018 Tr." and "2018 Ex.," respectively.

Based upon the foregoing and the entire record in this proceeding the Commission makes the following

FINDINGS OF FACT

Stipulations

1. On June 2, 2020, DEP and the Public Staff entered into and filed the First Partial Stipulation resolving some of the issues between the two parties, and on July 31, 2020, the Public Staff and DEP entered into and filed the Second Partial Stipulation, resolving several additional issues.

2. On various dates during this proceeding, DEP entered into and filed stipulations, and amendments thereto, with Harris Teeter (HT Stipulation), the Commercial Group (Commercial Group Stipulation or CG Stipulation), CIGFUR (CIGFUR Stipulation), Vote Solar (Vote Solar Stipulation), and a joint stipulation with NCSEA and NCJC et al. (NCSEA/NCJC et al. Stipulation), resolving some of the issues in this proceeding between these parties.

3. The stipulations with the Public Staff, Harris Teeter, Commercial Group, CIGFUR, Vote Solar, and jointly with NCSEA and NCJC et al. are products of the give-and-take negotiations among the parties.

Base Fuel and Fuel-Related Cost Factors

4. Consistent with Section IV.O of the Second Partial Stipulation, the total base fuel and fuel-related cost factors, by customer class, represented by the sum of the (a) respective base fuel and fuel-related cost riders set in Docket No. E-2, Sub 1142, and (b) the annual non-EMF fuel and fuel-related cost riders, by customer class, approved by the Commission in Docket No. E-2, Sub 1250, are just and reasonable to all parties.

Depreciation Study

5. Use of a 10% contingency for future “unknowns” in the estimate of future terminal net salvage costs is reasonable.

6. Use of the Company’s proposed future net salvage for mass property Accounts 364, Poles, Towers and Fixtures, Account 366, Underground Conduit and Account 369, Services is reasonable.

7. Use of an average service life of 15 years for the new advanced metering infrastructure (AMI) meters is reasonable.

8. The continued use of a 20-year amortization period for Accounts 391 and 397 is reasonable.

9. Except where specifically addressed in this Order, the depreciation rates proposed by DEP in this case, which are based on the Depreciation Study, filed by the Company as Spanos Direct Ex. 1, the Decommissioning Cost Estimate Study, and previously performed Burns and McDonnell decommissioning studies of each generating site, are just and reasonable.

Early Retirement of Coal Plants

10. The Company's integrated resource plan (IRP) proceeding is the appropriate venue for a thorough review of generating plant retirements.

11. The depreciation rates for the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants should be based upon the remaining useful life of the plants.

Coal and Nuclear Fleet Investments

12. DEP's investments in its coal fleet were reasonably and prudently incurred to enable DEP to meet its obligation to provide safe, adequate, and reliable electric service.

13. It is not necessary or appropriate at this time to impose a limit on the DEP's future investments in its coal-fired generating assets.

14. The costs related to DEP's investments in its nuclear generation fleet were reasonably and prudently incurred.

CCR Cost Recovery

15. North Carolina enacted the Coal Ash Management Act (CAMA) in 2014, which was amended in 2016, and the United States Environmental Protection Agency (EPA) promulgated its final rule — the Coal Combustion Residuals Rule (CCR Rule) — in 2015. Together, these state and federal laws and regulations introduced new requirements for the management of coal ash, or coal combustion residuals (CCR), and mandate the closure of the coal ash basins at all of the Company's coal-fired power plants.

16. Since its last rate case, DEP has incurred significant additional costs to continue the closure and compliance efforts related to these federal and state legal requirements and its management and storage of CCR. On a North Carolina retail jurisdictional basis, as of August 31, 2020, the CCR costs DEP incurred for which it seeks recovery in this rate case amount to $440,115,029, $399,134,625 of which are the actual coal ash basin closure and compliance costs incurred by the Company during the period from September 1, 2017, through February 29, 2020, and the remaining $40,980,404 of which are the financing costs incurred by the Company upon the deferred costs through August 2020.

17. On January 25, 2021, DEP, DEC, the Public Staff, AGO, and Sierra Club (collectively, CCR Settling Parties) filed a Coal Combustion Residuals Settlement Agreement (CCR Settlement) in the instant dockets, in the DEC Rate Case dockets, and in the 2018 Rate Case dockets resolving the issues among the CCR Settling Parties related to CCR cost recovery.

18. The CCR Settlement, which is the product of the give-and-take in settlement negotiations between the CCR Settling Parties, is material evidence in this proceeding and is entitled to be given appropriate weight in this proceeding, along with other evidence adduced by the Company and intervenor parties.

19. Section III.E of the CCR Settlement provides that the amount of CCR costs and financing costs sought for recovery in this case will be reduced by $261 million. Additionally, Section III.E provides for the recovery of financing costs sought for recovery in this case during the deferral period, calculated at the weighted average cost of capital, as well as during a five-year amortization period, calculated using: (i) DEP's cost of debt as previously stipulated by the Company and the Public Staff in the Second Partial Stipulation adjusted as appropriate to reflect the deductibility of interest expense; (ii) a cost of equity 150 basis points below the 9.60% stipulated to in the Second Partial Stipulation; and (iii) a 48% debt and 52% equity capital structure.

20. Section III.F of the CCR Settlement provides that the amount to be recovered of CCR costs incurred by DEP from March 1, 2020, through February 28, 2030, along with associated financing costs incurred during the deferral period, will be reduced by $162 million but allows for recovery of any remaining CCR costs, subject to determination by the Commission that such costs were reasonably and prudently incurred. Additionally, Section III.F provides for recovery of financing costs during the applicable deferral period, calculated at the weighted average cost of capital, and permits recovery of financing costs during the applicable amortization period, calculated using a reduced cost of equity.

21. Section III.D.i of the CCR Settlement provides that the CCR Settling Parties waive their right to assert that future CCR costs should be shared between the Company and ratepayers through equitable sharing of the costs or other adjustment except as provided in the CCR Settlement. Section III.D.ii provides that the CCR Settling Parties waive their right to challenge future CCR costs on the basis that the Company's prior coal ash management practices were inadequate and led to unreasonable CCR costs being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. Section III.D.iii of the CCR Settlement provides that the CCR Settling Parties reserve their right to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

22. Section III.G of the CCR Settlement provides for an allocation between DEP, DEC, and their customers of any proceeds from ongoing coal ash insurance litigation.

23. The provisions of the CCR Settlement are just and reasonable in light of all of the evidence presented. It is appropriate for the Company to reduce the balance of deferred CCR costs sought to be recovered in this rate case by $261 million. It is appropriate that the $261 million reduction reduce the deferred CCR costs as of December 31, 2020, and that DEP cease to accrue financing costs on that amount after December 31, 2020, and not seek to recover such financing costs from customers, as set forth in Section III.E of the CCR Settlement. After such reduction and updating financing costs through March 2021, the net amount for which the Company seeks recovery in this case is $191,577,737. It is further appropriate for the Company to defer CCR costs incurred since March 1, 2020, and to reduce the balance of deferred CCR costs sought to be recovered in its next general rate case by $162 million as set forth in Section III.F of the CCR Settlement. It is appropriate that no financing costs accrue on the $162 million as of December 31, 2020, as set forth in Section III.F of the CCR Settlement. The reduced financing costs agreed upon in Sections III.E and III.F of the CCR Settlement are appropriate.

ARO Accounting

24. DEP is required to comply with Generally Accepted Accounting Principles (GAAP), specifically, Accounting Standards Codification 410, Asset Retirement and Environmental Obligations (ASC 410) and Accounting Standards Codification 980, Regulated Operations (ASC 980).

25. DEP is required to comply with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA), specifically, General Instruction No. 25, Accounting for Asset Retirement Obligations.

26. Neither GAAP nor FERC accounting rules determine the proper principles of cost recovery for North Carolina retail ratemaking purposes; rather, the ratemaking treatment determined by the Commission in accord with the provisions of Chapter 62 of the General Statutes determines how the Company should account for costs and revenues under the applicable GAAP and FERC rules.

Capital Structure, Cost of Capital, and Overall Rate of Return

27. As set forth in Section III.B of the Second Partial Stipulation, the Public Staff and the Company agreed on a capital structure consisting of 52% common equity and 48% long-term debt.

28. The Company's embedded cost of debt is 4.04%, as set forth in Section III.B of the Second Partial Stipulation.

29. The rate of return on common equity (ROE) that the Company should be allowed an opportunity to earn is 9.60%, as set forth in Section III.B of the Second Partial Stipulation.

30. The overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 6.93%, as set forth in Section III.B of the Second Partial Stipulation.

31. The overall rate of return and ROE are supported by competent, material, and substantial record evidence; are consistent with the requirements of N.C.G.S. § 62-133 in light of changing economic conditions; and appropriately balance the Company's need to maintain the safety, adequacy, and reliability of its service with the benefits received by DEP's customers from safe, adequate, and reliable electric service.

32. The capital structure, ROE, and overall rate of return set by this Order will result in just and reasonable rates.

Cost of Service Adjustments

33. The Public Staff First and Second Partial Stipulations provide for certain accounting adjustments upon which DEP and the Public Staff have agreed; the revenue requirement effects of the settled issues are outlined in Smith Partial Settlement Ex. 3, Smith Second Settlement Ex. 3, Maness Stipulation Ex. 1, Schedule 1, and Maness Second Stipulation Ex. 1, Schedule 1 (the Partial Stipulation Revenue Requirement Exhibits). These agreed-upon accounting adjustments are just and reasonable to all parties in light of all the evidence presented.

Deferral of Grid Improvement Plan Capital Costs

34. DEP requested deferral of the capital costs for approximately $988 million in Grid Improvement Plan (GIP) spending to occur from January 2020 through 2022.

35. As a result of DEP's Second Partial Stipulation with the Public Staff and settlements with other parties DEP narrowed the scope of the GIP programs for which the Company seeks capital cost deferral and reduced its request to approximately $400 million in GIP spending from June 2020 through 2022.

36. DEP's reduced GIP deferral request as set forth in the Second Partial Stipulation is reasonable and should be approved subject to limitation.

37. DEP has the burden of proving its GIP spending is reasonable and prudent when it seeks to recover, in any future proceeding, GIP costs from customers.

38. GIP expenditures beyond those covered by the GIP deferral approved herein are to be informed by the Integrated Systems and Operations Planning (ISOP) process.

39. DEP should file a proposal for moving all DSDR and CVR costs into base rates with its next general rate case application.

Regulatory Asset and Liability Rider

40. The Company's proposed Regulatory Asset and Liability rider (RAL-1), which refunds approximately $2.1 million to customers over a one-year period, is just and reasonable and consistent with the Commission's directive relating to the treatment of net over-amortizations of expired regulatory assets and liabilities since the Company's last general rate case.

Tax Act Issues

41. DEP's proposed revision to its previously approved North Carolina excess deferred income taxes (EDIT) rider (EDIT-1) to reflect the change in the federal corporate income tax rate from 35% to 21%, is just and reasonable and should be approved.

42. Federal protected EDIT should be removed from DEP's proposed rider and amortized through base rates in accordance with the Internal Revenue Service (IRS) normalization rules as DEP and the Public Staff agreed in their First Partial Stipulation.

43. The federal unprotected EDIT should be flowed back to customers using a levelized five-year rider as DEP and the Public Staff agreed in the Second Partial Stipulation.

44. The federal provisional revenues should be flowed back to customers using a levelized two-year rider as DEP and the Public Staff agreed in the Second Partial Stipulation.

45. State EDIT should be flowed back to customers using a levelized two-year rider as DEP and the Public Staff agreed in the Second Partial Stipulation.

46. The provisions of the CIGFUR Stipulation regarding the appropriate methodology to flow back unprotected EDIT and provisional revenues are not just and reasonable and should not be approved.

47. All federal unprotected EDIT and provisional revenues should be refunded to customers using the methodology based on the amounts each class paid and, specifically, as a credit by specific customer class divided by the adjusted class' test year sales, as recommended by Public Staff witness Floyd.

48. The agreement between DEP and the Public Staff outlined in the Second Partial Stipulation concerning how to address future changes in the federal corporate income tax rate or North Carolina state corporate income tax rate which may occur during the respective amortization periods is reasonable and appropriate.

Cost Allocation Methodology

49. In the Second Partial Stipulation DEP and the Public Staff agreed to calculate and allocate the Company's cost of service based on a Summer Coincident Peak (SCP) allocation methodology to determine the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility.

50. As set forth in the CIGFUR Stipulation, the Company has committed to file in its next general rate case the results of a class cost-of-service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and to consider such results for the sole purpose of apportionment of the change in revenue to the customer classes.

Rate Design

51. It is appropriate for the Company to conduct a comprehensive rate design study as DEP agreed to in the Second Partial Stipulation and expanded on in this Order.

Affordability

52. It is appropriate for the Company to convene a stakeholder process tasked with addressing affordability issues for low-income residential customers as DEP agreed in the NCSEA/NCJC et al. Stipulation and the Second Partial Stipulation.

53. It is appropriate for the Company to provide its share, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC, of an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million) which will not affect rates, as DEP agreed in the NCSEA/NCJC et al. Stipulation.

54. It is appropriate for the Company to make an annual $2.5 million shareholder contribution to the Energy Neighbor Fund in 2021 and 2022 (for a total contribution of $5 million) which will not affect rates, as DEP agreed in the Second Partial Stipulation.

Storm Costs

55. DEP's costs of repairing the damage caused by Hurricanes Florence, Michael, Dorian, and Winter Storm Diego (Storm Costs), as presented by the Company in its Application and agreed to in the First Partial Stipulation are just and reasonable and were prudently incurred to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward remain subject to review pursuant to the provisions of N.C.G.S. § 62-172(a)(16)(c).

56. DEP's Storm Costs total $714.0 million, consisting of approximately $567.3 million in actually incurred or projected storm response operations and

maintenance (O&M) costs, approximately $68.6 million in capital investments, and approximately $78.1 million in carrying costs calculated using the Company's approved weighted average cost of capital through August 31, 2020.

57. Consistent with the First Partial Stipulation and the testimony of witness De May, DEP has withdrawn these costs, including capital investments, from the current rate case, except regarding the prudence determination reached above.

58. It is appropriate that DEP continue to defer the Storm Costs in a regulatory asset account until the date storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172 or until the Company seeks recovery of the Storm Costs through an alternative method of cost recovery.

59. It is appropriate that DEP continue to accrue and record carrying costs at the Company's approved weighted average cost of capital on the deferred balances in its storm cost recovery deferred account pending recovery through securitization, subject to the assumptions and conditions agreed to in the First Partial Stipulation.

60. A ten-year normalized adjustment to DEP's revenue request to account for anticipated storm expenses that are too small to securitize is appropriate for use in this proceeding.

61. It is appropriate to establish a Storm Cost Recovery Rider for the Company and to set the initial balance for that rider at $0 in conformance with the provisions of the First Partial Stipulation.

Service Regulations, Vegetation Management Reporting Obligations, and Quality of Service

62. The amendments to the service regulations proposed by the Company are reasonable and should be approved.

63. The Company shall file an annual report of its Vegetation Management performance similar to the DEC report format provided in Docket No. E-7, Subs 1146 and 1182.

64. The overall quality of electric service provided by DEP is good.

Advanced Metering Infrastructure and Green Button Connect

65. DEP's costs of deploying AMI meters were prudently incurred and are reasonable.

66. It is appropriate for DEP to recover Rider MRM costs not recovered from customers opting out of AMI meters from all DEP customers.

67. Whether DEP should implement Green Button "Connect My Data" should be addressed in the ongoing investigation and rulemaking in Docket No. E-100, Sub 161.

Focal Point Project Costs

68. The capital costs associated with Project Focal Point (Focal Point) should be removed from rate base.

Roxboro Wastewater Treatment Plant Deferral

69. DEP's request for an accounting order to establish a regulatory asset upon retirement of the Roxboro Wastewater Treatment Plant, at the time of the plant's anticipated early retirement in 2021, to defer the unrecovered remaining net book value of the plant and costs related to obsolete inventory, net of salvage, at the time of retirement is reasonable and is approved.

Accounting for Deferred Costs

70. The Company is authorized to receive a specific amount of revenue for each of the deferred costs approved by this Order. If DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Just and Reasonable Rates

71. The base non-fuel and base fuel revenues and rates approved herein are just and reasonable to the customers of DEP, to DEP, and to all parties to this proceeding, and serve the public interest.

Revenue Requirement

72. After giving effect to the portions of the settlement agreements approved herein and the Commission's decisions on contested issues, the annual revenue requirement for DEP will allow the Company a reasonable opportunity to recover its operating costs and earn the rate of return on its rate base that the Commission has found just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

Stipulations

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations between DEP and other parties; the testimony and exhibits of DEP witness De May and Public Staff witness Maness; and the entire record in this proceeding.

Summary of the Evidence

Public Staff First and Second Partial Stipulations

On June 2, 2020, DEP and the Public Staff entered into and filed the First Partial Stipulation resolving some of the issues between the two parties, and on July 31, 2020, the Public Staff and DEP entered into and filed the Second Partial Stipulation, resolving several additional issues in this proceeding.

Witness De May explained that the First Partial Stipulation resolves several of the revenue requirement issues between the Company and the Public Staff. Tr. vol. 11, 782. Revenue requirement adjustments were agreed upon in the First Partial Stipulation for Storm Costs, Aviation, Executive Compensation, Board of Directors, Lobbying, Sponsorships & Donations, Rate Case Expenses, Outside Services, Severance, Incentive Compensation, the Asheville Combined Cycle (CC) project, W. Asheville Vanderbilt 115 kV project, Credit Card Fees, End of Life Nuclear Reserve, Protected Federal EDIT, and treatment of the CertainTEED payment obligation in this rate case. *Id.* at 783-84. These accounting and ratemaking adjustments and the resulting revenue requirement effect of the First Partial Stipulation are shown in Schedule 1 of Maness Stipulation Exhibit 1 and Smith Partial Settlement Ex. 3, which provide sufficient support for the annual revenue required on the issues agreed to in the First Partial Stipulation. The revenue requirement impact of the issues settled in the First Partial Stipulation is a reduction of the base revenue requirement of approximately $123,904,000 to $130,106,000, depending on the resolution of the Unresolved Issues.

The Second Partial Stipulation is based upon the same test period as the Company's Application, adjusted for certain known changes in revenue, expenses, and rate base through February 29, 2020 and May 31, 2020. The Second Partial Stipulation outlines the Unresolved Issues as follows: (1) cost recovery of the Company's coal ash costs, recovery amortization period and return during the amortization period; (2) the depreciation rates appropriate for use in this case, including the Company's proposal to shorten the lives of certain coal-fired generating facilities; and (3) any other revenue requirement or nonrevenue requirement issue other than those issues specifically addressed in this Second Partial Stipulation, the First Partial Stipulation, or agreed upon in the testimony of DEP and the Public Staff. Second Partial Stipulation, § II.

Witness De May testified that DEP and the Public Staff were able to reach the Second Partial Stipulation, which resolves most but not all of the remaining revenue requirement issues between DEP and the Public Staff. Tr. vol. 11, 789. Witness De May provided an overview of the major components of the Second Partial Stipulation, including an agreement regarding shareholder contributions to the Energy Neighbor Fund, cost of capital, return of state and federal EDIT to customers, deferral accounting treatment of certain GIP programs, cost of service methodology for this case, inclusion of the May

2020 Updates to certain pro forma adjustments subject to the Public Staff's audit of the updates and other terms concerning the May updates, the annual funding amount for the Company's Nuclear Decommissioning Trust Fund, and the amortization period for non-ARO environmental costs. *Id.* at 789-92.

In addition, witness De May outlined other areas of agreement, including terms governing the start date of the evidentiary hearings to allow time for the Public Staff to audit the May Updates, ongoing assessments of the cost effectiveness of GIP-related projects, clarification of GIP costs that are eligible for deferral, commitments to future cost of service studies, rate design issues, and commitments to conduct audits and reporting obligations regarding plant, materials and supplies inventory, vegetation management, and service reliability index reporting. *Id.* at 792. These accounting and ratemaking adjustments and the resulting revenue requirement effect of the Second Partial Stipulation are shown in Maness Second Stipulation Ex. 1, Schedule 1 and Smith Second Settlement Ex. 3, which provide sufficient support for the annual revenue required on the issues agreed to in the Second Partial Stipulation. The Company's calculation of the revenue requirement impact of the issues settled in the Second Partial Stipulation is an increase in the base revenue requirement of approximately $19,495,000, to be further adjusted by the Public Staff's recommendations in its testimony filed on September 15 and 16, 2020, and pending resolution of the Unresolved Issues.

Witness De May testified that he attended public hearings held by the Commission in this matter and personally heard from dozens of customers who are concerned about the impacts of any rate increase on their families and businesses and noted that the Company is very mindful of these concerns. *Id.* at 793. Witness De May stated that the concessions the Company has made in the Public Staff Partial Stipulations fairly balance the needs of DEP customers with the Company's need to recover investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to its customers, particularly so in the Second Partial Stipulation in light of the current economic conditions of many of the Company's customers due to the COVID-19 pandemic. *Id.*

Public Staff witness Maness testified that from the perspective of the Public Staff, the most important benefits provided by the Public Staff Partial Stipulations are: (a) an aggregate reduction in the Company's proposed revenue increase as to specific expense items agreed to by DEP and the Public Staff in this proceeding, and (b) the avoidance of protracted litigation between DEP and the Public Staff before the Commission and possibly the appellate courts. Tr. vol. 16, 35. Based on these ratepayer benefits, as well as the other provisions of the Public Staff Partial Stipulations, the Public Staff believes the Public Staff Partial Stipulations are in the public interest and should be approved. *Id*.

Section III of the First Partial Stipulation outlines a number of accounting adjustments to which DEP and the Public Staff have agreed as well as Section III.J of the Second Partial Stipulation. These accounting adjustments are fully discussed later in this Order.

Section IV of the Second Partial Stipulation outlines a number of aspects of the Company's record keeping and reporting practices to which DEP and the Public Staff have agreed.

CIGFUR Stipulation

On June 26, 2020, the Company and CIGFUR entered into and filed the CIGFUR Stipulation. No testimony supporting the settlement was filed.

As part of the CIGFUR Stipulation, DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. CIGFUR Stipulation, § II. Subsequently, on August 6, 2020, the Stipulation was amended to state that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of the Stipulation should be deemed to be fulfilled.

In addition, CIGFUR agreed to support the Company's request for a deferral of GIP costs over three years. CIFGUR Stipulation, § III.A. Because the three-year GIP plan contains estimates, CIGFUR's support for the GIP deferral will be subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases. To the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap or to otherwise limit the maximum allowed amount of the three-year GIP deferral, CIGFUR supports such cost containment measures.

Section III.B of the CIGFUR Stipulation provides that in the next rate case, DEP will propose to allocate the deferred GIP costs among classes, consistent with its distribution cost allocation methodologies proposed in this docket, including use of the minimum system method (MSM) and voltage differentiated allocation factors for distribution plant. Additionally, with Commission approval, the Company will use this methodology to allocate GIP costs during the three years for which it may seek recovery in future rate cases.

Under Section IV, the parties agreed to refund unprotected EDIT on a uniform cents per kilowatt-hour (cents/kWh) basis.

Under Section V, DEP and CIGFUR agreed to five conditions related to cost of service and rate design. The first condition would obligate DEP to discuss and consider potential cost of service methodologies and to consider the results of a cost of service study based on the Summer/Winter Coincident Peak method. The second condition would require DEP in its next rate case to adjust peak demand to remove curtailable/non-firm load, even when the load reduction is not requested. The third condition would require DEP in its next two fuel proceedings to propose the uniform percentage average bill adjustment methodology. The fourth condition would require DEP in its next three rate cases to allocate distribution expenses using the MSM unless the Commission rejects the method. In the fifth, and final condition, the Company agreed to explore certain rate designs and file the rates if there was interest from CIGFUR customers.

Harris Teeter/Commercial Group Stipulations

On June 8, 2020, DEP and Harris Teeter entered into and filed the HT Stipulation, and on June 9, 2020, DEP and the Commercial Group entered into and filed the CG Stipulation. These settlements are substantially similar, and they resolve several issues between DEP and these parties, among other things, ROE and capital structure, GIP, and some rate design issues. No testimony supporting either settlement was filed.

As part of these stipulations DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. CG Stipulation, § 5; HT Stipulation, § 5. Subsequently, both stipulations were amended to state that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, Paragraph 5 of each Stipulation should be deemed to be fulfilled.

As part of its stipulation with DEP the Commercial Group neither opposes nor specifically supports the approval of the Company's requested GIP deferral. CG Stipulation, § 1. Harris Teeter supports the approval of the Company's requested GIP deferral with certain conditions detailed therein, including a reservation of Harris Teeter's right to take any position as to the reasonableness of specific GIP costs in a future rate case. HT Stipulation, § 1.

Further, DEP, Commercial Group, and Harris Teeter agreed that any GIP costs allocated to SGS-TOU customers shall be recovered via SGS-TOU demand charges. They also agreed that the percentage base rate increase for Rate Schedule SGS-TOU and Rate Schedule MGS shall be the same, while acknowledging that DEP shall have the right to adjust the rates for Rate Schedule CSE and Rate Schedule CSG more than the percentage base rate increase for Rate Schedule MOS. CG Stipulation, § 3; HT Stipulation, § 3. In addition, the settlements provide that the SGS-TOU on-peak and off-peak energy demand changes shall be increased by a percentage that is no greater than half of the approved overall increase percentage for the SGS-TOU rate schedule, but that the demand charges shall be adjusted by the amount necessary to recover the final SGS-TOU revenue target. CG Stipulation, § 4; HT Stipulation, § 4.

NCSEA/NCJC et al. Stipulation

On July 23, 2020, DEP and NCSEA and NCJC et al. entered into and filed the NCSEA/NCJC et al. Stipulation, resolving some of the issues in this proceeding between these parties. No testimony supporting the settlement was filed.

As part of the NCSEA/NCJC et al. Stipulation, the parties initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. NCSEA/NCJC et al. Stipulation, § II. Subsequently, on August 10, 2020, the parties filed an amendment to their stipulation providing that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, Paragraph II of the Stipulation should be deemed to be fulfilled.

NCSEA/NCJC et al. also agreed to support the Company's request for an accounting order for approval to defer GIP costs for investments in Integrated System Operations Planning (ISOP), Integrated Volt Var Control (IVVC), Self-Optimizing Grid (SOG), Distribution Automation, Transmission System Intelligence, the Distributed Energy Resources (DER) Dispatch Tool, and the 44 kilovolt Line Rebuild. NCSEA/NCJC et al. believe that these investments will directly enable and support the greater utilization of DERs on the Company's system. For all other GIP investments proposed by DEP, NCSEA/NCJC et al. do not oppose the requested deferral accounting treatment. To the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, NCSEA/NCJC et al. support such cost containment measures, but subject to a reservation of their rights to review and object to the reasonableness of specific project costs in future rate cases.

Pursuant to other provisions of the NCSEA/NCJC et al. Stipulation DEP agreed:

(1) to provide, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC (DEC), an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million);

(2) that within six months of the effective date of the Stipulation, in addition to the low-income collaborative proposed by DEP, the parties agreed to collaborate to design additional low-income EE/DSM program pilots to present to the DEC and DEP EE/DSM Collaborative for consideration. Further, on the condition that the majority of EE/DSM Collaborative participants and DEP and DEC support the program pilots, DEP agreed to file for approval of the program pilots in North Carolina and South Carolina;

(3) within six months of the effective date of the Stipulation, the parties agreed to collaborate to design a tariffed on-bill pilot program, which shall include a Pay-As-You-Save® or other mutually agreeable alternative program design, for customers in North Carolina, addressing several listed issues. Within 18 months of the effective date of this agreement, DEP agreed to either (i) file the pilot for approval with the Commission, provided the parties mutually agree to the terms of the pilot program that is not less than three years in length and, in conjunction with the concurrent commitment of DEP, includes a combined total of no fewer than 700 but no more than 1000 residential customers, or (ii) file a status report with the Commission in this docket.

In addition, DEP agreed to preview a Distributed Generation Guidance Map for North Carolina with the DER Interconnection Technical Standards Review Group (TSRG) in the TSRG meeting during the third quarter of 2020, as well as in the August 2020 ISOP stakeholder meeting, after which DEP will incorporate TSRG and ISOP stakeholder input as appropriate and publish the Distributed Generation Guidance Map for North Carolina.

Further, DEP agreed to include in its 2021 IRP details about how both existing and new DERs and non-wires applications will be examined in its ISOP as means to defer traditional capital investments in the system. DEP will also implement the basic elements of the ISOP process in the 2022 IRP. Following the 2024 IRP, but no later than December 31, 2024, DEP agreed to provide hosting capacity analyses for a representative sample of DEP North Carolina circuits with other provisions and contingencies.

Finally, DEP agreed that it will reasonably include NCSEA/NCJC et al. for input and feedback at material points in its selection process as it identifies the tools and capabilities necessary for ISOP implementation. DEP will also reasonably consider and, where appropriate, incorporate input from the parties regarding the parameters that ISOP will use to assess issues such as distribution investment needs; the use of existing and future distributed energy resources and non-wires applications; load forecasts; pricing assumptions; and modeling inputs, keeping in mind the overall objective of developing investment plans that meet customer needs and preferences by capturing efficiencies from being a vertically integrated electric utility.

Vote Solar Stipulation

On July 9, 2020, DEP and Vote Solar entered into and filed the Vote Solar Stipulation, resolving some of the issues in this proceeding between these parties. No testimony supporting the settlement was filed.

As part of the Vote Solar Stipulation, DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. Vote Solar Stipulation, § II. Subsequently, on August 5, 2020, the parties filed an amendment to the Vote Solar Stipulation, providing that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, Paragraph II of the Stipulation should be deemed to be fulfilled.

Further, Vote Solar agreed to support the Company's request for an accounting order for approval to defer GIP costs for investments in Integrated System Operations Planning (ISOP), Integrated Volt Var Control (IVVC), Self-Optimizing Grid (SOG), Distribution Automation, Transmission System Intelligence, the Distributed Energy Resources (DER) Dispatch Tool, and the 44 kilovolt Line Rebuild. Vote Solar believed that these investments will directly enable and support the greater utilization of DERs on the Company's system. For all other GIP investments proposed by DEP, Vote Solar did not oppose the requested deferral accounting treatment. To the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, Vote Solar supported such cost containment measures. Further, Vote Solar's support for the GIP deferral is subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases.

In addition, DEP committed with Vote Solar to develop potential pilot customer programs prior to the submission of the 2022 IRP to optimize the capability of the GIP investments to support greater utilization of DERs, including customer sited solar and/or storage facilities (e.g., net metering successor), microgrid systems that benefit and would be paid for by specific benefitted customers, and programmable and load controllable devices or appliances for use in residential and nonresidential demand response programs. If DEP and Vote Solar mutually agree that these programs are cost-effective and meet appropriate Commission requirements, DEP agreed to file such pilot programs for approval by the Commission, and Vote Solar agreed to support such approval by the Commission.

Moreover, DEP agreed that within six months from the effective date of the Commission's order in this docket, DEP will convene a Climate Risk & Resilience Working Group (Working Group), governed by several parameters set out in the Stipulation. Within sixty days of the effective date of the Commission's order, the Company will make an informational filing in the docket to describe its scoping plan and proposed schedule for the Working Group and will give notice of such filing to all interested parties in all North Carolina and South Carolina dockets and stakeholder processes to which it is a party related to climate or decarbonization policy, the GIP, IRP, and ISOP.

DEP further agreed to fund a third-party consultant with experience developing models or analyses for quantifying climate-related impacts on the electric grid to assist stakeholders and the Company with the Working Group, subject to the contingency that DEP will recover the cost of the third-party consultant from ratepayers.

Discussion and Conclusions

As none of the partial stipulations have been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject each of the stipulations is governed by the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*). In *CUCA I*, the Supreme Court held:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the

> evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] . . . satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." *Id.* at 231-32, 524 S.E.2d at 16.

The Commission finds and concludes that the provisions of the First and Second Partial Stipulations, as well as the stipulations with CIGFUR, Harris Teeter, Commercial Group, Vote Solar, NCSEA, and NCJC et al. result from the give-and-take between DEP and the stipulating parties and represent a compromise that is fair and adequate to each party. Pursuant to *CUCA I* and *II*, these nonunanimous stipulations are some evidence to be considered by the Commission in reaching its decision in this case. The Commission has fully evaluated the provisions of these stipulations and concludes, in the exercise of its independent judgment, that the stipulations should be accepted, in part, and rejected, in part, consistent with the specific discussion and resolution of the various issues discussed below. The parties are free to enter into stipulated provisions that pertain to actions or positions to be taken outside the confines of this proceeding; however, to the extent that DEP committed to certain actions or positions in future proceedings the Commission concludes that they are not relevant to any issue before the Commission in this case and do not tie the Commission's hands or limit future investigations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

Base Fuel and Fuel-Related Cost Factors

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEP witnesses McGee and Smith, and Public Staff witnesses Metz and Maness; and the entire record in this proceeding.

Summary of the Evidence

In her direct testimony DEP witness McGee supported the fuel component of proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in Smith Direct Exhibit 1. Tr. vol. 11, 50-51. Witness McGee proposed to use the total prospective fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1173, and implemented December 1, 2018. *Id*. at 50. Witness McGee explained that these factors represented the fuel-related amounts DEP expected to collect from its North Carolina retail customers through its approved rates in the next billing period, and that DEP's intent in using the fuel-related factors that represent expected future rates as a component of its proposed new rates was to make it clear that the Company is requesting a rate increase that relates to non-fuel revenues only. *Id*. at 50-51.

Public Staff witness Metz testified that the base fuel factor in DEP's Application was appropriate for the Company's initial filing as it reflected the rates in effect at the time of the filing. Witness Metz stated that since the approved base fuel rate in Docket No. E-2, Sub 1204, DEP's previous annual fuel proceeding, went into effect December 1, 2019, the Sub 1204 rates would have to be refined in future Public Staff filings in this case. Witness Metz also stated that a future update would need to reflect the refinement of catalyst depreciation being shifted from fuel rates to base rates. Tr. vol. 15, 852-53.

In her supplemental testimony DEP witness McGee supported a revised base fuel factor to conform to the fuel rates approved in Sub 1204, and updated DEP's fuel costs based on revised weather and customer growth adjustments. Tr. vol. 11, 55-56.

In her supplemental testimony Company witness Smith presented an adjustment to update fuel costs to the Sub 1204 approved rates, explaining that the adjustment was also revised to reflect removal of catalyst depreciation from fuel clause recovery. Witness Smith also explained that after discussion with the Public Staff, DEP concluded that recovery of this expense in base rates is the most reasonable cost recovery approach. Tr. vol. 13, 172.

The Company filed its subsequent fuel factor adjustment case in Docket No. E-2, Sub 1250 on June 9, 2020. Section IV.O of the Second Partial Stipulation provided that should a final Commission order be issued in DEP's then ongoing annual fuel rider proceeding, Docket No. E-2, Sub 1250 (Sub 1250), prior to the date the proposed orders are due in this general rate case proceeding, the total of the approved base fuel and fuel related cost factors, by customer class, will be the sum of the respective base fuel and fuel-related cost factors set in Sub 1142 and the annual non-EMF fuel and fuel-related cost riders approved by the Commission in Sub 1250. Company witness Smith and Public Staff witness Maness supported the provision for the total approved base fuel and fuel related cost factors through their testimony in support of the Second Partial Stipulation. Tr. vol. 13, 260-61; tr. vol. 16, 34.

The Commission issued a final order in the Sub 1250 fuel rider proceeding on November 30, 2020. In the Sub 1250 order, the Commission concluded that, effective for service rendered on and after December 1, 2020, DEP shall adjust the base fuel and fuel-related costs in its North Carolina retail rates as approved in Sub 1142 of 1.993 cents/kWh, 2.088 cents/kWh, 2.431 cents/kWh, 2.253 cents/kWh, and 0.596 cents/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively (all excluding regulatory fee), by amounts equal to 0.087 cents/kWh, 0.038 cents/kWh, (0.203) cents/kWh, (0.049 cents/kWh), and 0.796 cents/kWh, respectively. This results in total non-EMF fuel and fuel-related factors of 2.080 cents/kWh for the Residential class, 2.126 cents/kWh for the Small General Service class, 2.228 cents/kWh for the Medium General Service class, 2.204 cents/kWh for the Large General Service class, and 1.392 cents/kWh for the Lighting class, excluding the regulatory fee.

According to witness McGee the Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings. Tr. vol. 11, 52, 57. As such, there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. *Id*.

Discussion and Conclusion

No intervenor offered any evidence contesting the testimony of Company and Public Staff witnesses that supported the base fuel and fuel-related cost factors therein or the Public Staff Second Stipulation provision for the Company's base fuel and fuel related cost factors. Further, the Commission gives significant weight to Section IV.O of the Stipulation regarding the base fuel and fuel-related costs factors. Accordingly, the Commission finds and concludes for purposes of this proceeding that the total of the approved base fuel and fuel-related costs factors, by customer class — the sum of the respective base fuel and fuel-related costs factors set in Sub 1142 and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Sub 1250 — are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-9

Depreciation Study

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witness Spanos, Public Staff witness McCullar, and FPWC witness Brunault; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness Spanos testified to the new deprecation study prepared for DEP for use in this proceeding. Tr. vol. 11, 210-11. He provided a copy of the Depreciation Study as

Exhibit 1 to his direct testimony. As explained by witness Spanos, the Depreciation Study included updates to estimates of final plant depreciation costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. In addition, witness Spanos noted that the Depreciation Study incorporates the full decommissioning cost values from the previously performed Burns and McDonnell decommissioning studies. These decommissioning studies included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

Witness Spanos testified as to how he determined the depreciation rates included in the depreciation study. He further testified that he used the same methods and procedures to produce the current depreciation study as he has done in previous DEP depreciation studies.

Next, witness Spanos discussed the life span estimates for DEP's production facilities. He explained that those estimates are based on informed judgment that incorporates factors for each facility such as the technology of the facility, management plans and outlook for the facility, and estimates for similar facilities at other utilities. Witness Spanos stated that the life span estimates for nuclear and hydro facilities that have operating licenses were based on the license expiration dates for each facility. *Id.* at 218. The life span estimates used for depreciation rates for various fossil plants were also updated due to proposed changes to the probable retirement dates, with the life spans at Mayo Unit 1 and Roxboro Units 3 and 4 proposed to be shorter than currently approved. He further noted that the Asheville coal units 1 and 2 that were scheduled for retirement in 2019 will continue to be recovered through December 2027. *Id*.

Witness Spanos also discussed DEP's continued deployment of legacy electric meters with new technology meters, which was planned to be completed by the end of 2020. He indicated that, consistent with the Sub 1142 Order, the net book value (approximately $68 million) of the legacy meters will be amortized over 10 years. *Id*. at 219. Witness Spanos testified that the Depreciation Study included depreciation rates for the new Asheville combined cycle facility, with a 40-year life span for the location, as well as for new battery storage assets for generation, transmission, and distribution, with a 15-year life span for those resources. *Id.* at 226.

Witness Spanos also testified regarding net salvage. He testified that net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage. Witness Spanos testified that the net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided by the Company's operating personnel, general knowledge and experience of industry practices; and trends in the industry. The statistical net salvage analyses incorporate the Company's actual historical data for the period 2003 through 2018 and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. He stated that trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

FPWC Testimony

FPWC witness Brunault recommended two changes to the assumptions used in the 2018 Depreciation Study. He first recommended that the life spans of Mayo Unit 1 and Roxboro Units 3 and 4 be consistent with the retirement dates in DEP's 2019 IRP Update Report filed with the Commission on September 3, 2019 pursuant to Docket No. E-100, Sub 157, rather than the earlier dates utilized in the 2018 Depreciation Study. Tr. vol. 14, 52-56. He further recommended that the contingency allowance utilized in the 2018 Depreciation Study be reduced from 20% to the 10% approved by the Commission in the Sub 1142 proceeding. *Id*. at 69-71.

Public Staff Testimony

Public Staff witness McCullar testified that DEP was proposing an increase of $145 million in annual depreciation accrual. Tr. vol. 15, 781. She summarized that the Public Staff was recommending adjustments to reduce DEP's requested depreciation by $66.4 million. She noted that the Public Staff proposes changes to DEP's requested depreciation rates in the following functional categories: (1) Steam Production Plant (DEP is proposing 5.33% and Public Staff is proposing 4.13%); (2) Hydraulic Production Plant (DEP is proposing 3.70% and the Public Staff is proposing 3.65%); (3) Other Production Plant (DEP is proposing 5.08% and the Public Staff is proposing 5.03%; (4) Distribution Plant (DEP is proposing 2.34% and the Public Staff is proposing 2.32%); and (5) General Plant (DEP is proposing 5.74% and the Public Staff is proposing 4.39%). She noted that total depreciable plant as proposed by DEP is 3.60% and 3.35% as recommended by the Public Staff.

Witness McCullar specifically addressed the following additional issues in her testimony:

Contingency

Witness McCullar testified that DEP was again including a 20% contingency for future "unknowns", as included by DEP in this proceeding. She proposes to eliminate the 20% contingency for future "unknowns" and noted the 2018 DEP Rate Order in which the Commission ordered that a 10% contingency factor be used.

Mass Property Future Net Salvage

Witness McCullar testified that she had reviewed the reasonableness of DEP's proposed future net salvage for a mass property account and she was recommending three changes: (1) a -75% for the Poles, Towers and Fixtures, Account 364, which is different than the proposed -100% by DEP; (2) a -10% for the Underground Conduit, Account 366, which is different than DEP's proposed -15% for this account; and

(3) a -15% for the Services, Account 369, which is different than DEP's proposed -20% for this account. Witness McCullar noted that salvage ratios are a function of inflation and that the calculation of the historic net salvage ratio includes the impact of high historic inflation rates since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic dollars. In other words, due to inflation, the amounts in numerator and denominator of the net salvage ratio are at different price levels. Witness McCullar testified that her proposed future net salvage accrual amounts consider DEP's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and her previous experience.

AMI Meters

DEP requested a 15-year depreciation life for AMI meters in this proceeding. As explained by witness Spanos, a 15-S2.5 survivor curve was recommended by DEP for AMI meters. Tr. vol. 11, 197. This estimate was consistent with the manufacturer's recommendation for the physical life of the AMI meters and accounted for alternative reasons for retirement such as damage or obsolescence. *Id.*

Public Staff witness McCullar recommended a 17-year service life for AMI meters. Tr. vol. 16, 615. Witness McCullar testified that a 17-year life is in the middle of the manufacturer's range, is a reasonable estimate based on the manufacturer's expected life of the AMI meters, and is fair to the Company and the ratepayer. *Id.*

Continued Use of Amortization Period for General Plant Accounts 391 and 397

Public Staff witness McCullar testified that in the Sub 1142 proceeding, the Commission found that the 20-year amortization period stipulated by the Public Staff and DEP for two general plant accounts: Account 391, Office Furniture and Equipment; and Account 397, Communication Equipment, was reasonable. Tr. vol. 15, 802-03. In this proceeding, DEP proposed to change the current approved 20-year amortization period for Account 391, Office Furniture and Equipment to a 15-year amortization, and the current approved 20-year amortization period for Account 397, Communication Equipment, to a 10-year amortization period. Public Staff witness McCullar noted that the 2018 Depreciation Study did not provide any data supporting the proposed change but noted that the lack of life data is not uncommon for amortized accounts due to the change in record-keeping when an account switches from depreciation accounting to amortization accounting. *Id.* at 805. Witness McCullar further explained that under amortization accounting, DEP no longer keeps the detailed records needed to populate the original life tables. DEP tracks the installation year, but the asset will be retired off the books when it reaches the approved average service life, regardless of whether that asset is still in service. She stated that the use of amortization accounting for these smaller value general plant accounts is used to minimize the accounting expense involved in keeping the detailed records used in depreciation accounting. *Id.*

Witness McCullar further testified that prior to the switch to amortization accounting in the Sub 1142 Proceeding, the approved service life for Account 391, Office Furniture and Equipment was 20 years, and the approved service life for Account 397, Communication Equipment was 27 years.

DEP Rebuttal Testimony

DEP witness Spanos noted his disagreement with the recommendations of FPWC witness Brunault and Public Staff witness McCullar to continue to use the 10% contingency previously approved by the Commission, stating that the terminal net salvage estimates used in the calculation of depreciation rates were based on a comprehensive decommissioning study that incorporated a 20% contingency. Tr. vol. 16, 295. He did not, however, provide any specific breakdown of costs to support the statement, other than to indicate that it was supported by the testimony of DEP witness Kopp in the Sub 1142 proceeding, and that the context of other proposals in this case and that coal ash costs show that end of life costs can be higher than originally anticipated provide additional support for the need for contingency. *Id.* at 295-96.

Regarding the adjustments to mass property accounts, DEP witness Spanos in rebuttal stated that Public Staff witness McCullar's recommendations for production plant accounts were consistent with the Commission's decision in the Sub 1142 Order, her recommendations regarding mass property distribution plant were not consistent with prior Commission decisions. *Id.* at 285. Further, he noted that FERC has confirmed that the estimated future net salvage costs should be included in depreciation. *Id*. at 290. He also testified that he did not believe that witness McCullar's analysis provides a reasonable basis to estimate future net salvage because it is based on the premise that depreciation accruals for net salvage should be similar to, if not the same as, the net salvage occurred each year. *Id*. at 294. He stated that the goal of depreciation is to recover capital costs, including net salvage over the service life of the assets, and that there is not necessarily alignment between depreciation accruals for net salvage and incurred net salvage. Lastly, he noted that expressing historical net salvage as a percentage of historical retirements as he proposes properly recognizes the relationship between net salvage and retirements. *Id.* at 295.

Regarding the lifespan of the AMI meters, DEP witness Spanos acknowledged on rebuttal that the Commission accepted a 17-year average service life for AMI meters in the Sub 1142 proceeding but noted that the Commission adopted a 15-year average service life for AMI meters in the last DEC rate case in Docket No. E-7, Sub 1146 (Sub 1146). *Id*. at 296-97. He recommended continuing to use the 15-S2.5 survivor curve, which he stated is consistent with the manufacturer's recommendation for the physical life of AMI meters but also considers that meters are retired for other reasons, such as damage or obsolescence. *Id.*

On cross-examination DEP witness Spanos acknowledged that although the Commission had concluded in the Sub 1146 Order that production plant accounts should be escalated to the date of retirement it had not made such a finding related to mass property salvage accounts. *Id.* at 373-74. Further, he acknowledged that the FERC Order discussed in his testimony did not address mass property net salvage accounts. *Id.* at 376.

During redirect DEP witness Spanos stated there was no compelling reason for DEP to use a different amortization period for these accounts than DEC, also noting that witness McCullar was a witness in the current DEC case in Docket No. E-7, Sub 1214, but had not challenged the amortization periods for these two accounts in that case. *Id.* at 305-06. He further disputed Public Staff witness McCullar's analysis in the Sub 1142 proceeding used to support the longer lives for the assets, noting that it relied in part on historical life analysis and that, due to the nature of the assets in these accounts (many units with small dollar values), many companies historically had difficulty tracking retirements. *Id.*

DEP witness Spanos also disputed witness McCullar's proposals for Accounts 391 and 397, in that she had excluded "millions of dollars of investment from her calculations of depreciation expense" for the two accounts. *Id.* at 307; *see also id.* at 383-86.

Discussion

Contingency Factor

Public Staff witness McCullar recommended that the currently approved 10% contingency for future "unknowns" included in DEP's estimate of future terminal net salvage costs continue to be used, as opposed to the 20% proposed by the Company. Tr. vol. 15, 789. Witness McCullar noted that in the Sub 1146 Order, the Commission approved the use of a 10% contingency factor, stating that:

> The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e. increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.

2018 DEC Rate Order at 172-73.

In rebuttal witness Spanos testified that the terminal net salvage estimates used in the calculation of depreciation rates were based on a decommissioning study performed by Burns and McDonnell. The Decommissioning Study incorporates a 20% contingency and this study, as well as DE Progress witness Kopp's testimony in DEP's previous rate case, provide the justification for this contingency factor. Tr. vol. 16, 295-96. Witness Spanos further noted that the intent of adding the contingency is to ensure that decommissioning activity is fully funded at the point of retirement.

The Commission agrees with DEP that including a contingency is a standard industry practice to cover potential unknown or unexpected costs. However, the Commission also agrees with the Public Staff that DEP has presented no new information or data supporting the need for a contingency percentage greater than the 10% contingency agreed to by stipulation and accepted in the Sub 1142 Order, or the 10% contingency approved by the Commission in the Sub 1146 Order for DEC. As quoted above, in that proceeding, the Commission expressed some concern regarding the accuracy of the Decommissioning Study, finding that DEC failed to consider certain factors, but concluded that a 10% contingency was fair to all parties.

The Commission acknowledges witness Spanos's experience and expertise, yet it notes that the contingency percentage utilized in the Depreciation Study and recommended in his testimony is based on the same Decommissioning Study used in the Sub 1142 proceeding. In addition, witness Spanos did not provide any new data or information to support his claims regarding recent industry experience supporting an increased contingency percentage. This unsupported position would inappropriately shift a greater portion of the risk of future unknown, unidentified costs on current ratepayers.

The Commission finds that the increased contingency proposed by DEP in this proceeding lacks sufficient basis and therefore concludes that it is reasonable and appropriate for DEP to continue to use a contingency factor of 10% for net terminal salvage.

Mass Property Future Net Salvage

Net salvage estimates are expressed as a percentage of the original cost retired. Tr. vol. 16, 286. The method for determining the estimated net salvage percent depends on the type of property. *Id.* For power plants, the estimate is typically based on a decommissioning study, with additional net salvage incorporated for interim retirements. *Id*. at 286-87. For mass property accounts such as those for transmission and distribution plant, net salvage estimates are based in part on statistical analyses of historical net salvage data. *Id.* at 287. In this case, the statistical net salvage analyses incorporate the Company's actual historical data from 1979 through 2018 and considers the cost of removal and gross salvage ratios to the associated retirements during the 40-year period. *Id.* at 249.

Witness Spanos recommended a net salvage percentage of negative 100% for Account 364, Poles, Towers and Fixtures, negative 15% for Account 366, Underground Conduit, and negative 20% for Account 369, Services. Witness McCullar recommended a future net salvage percent of negative 75% for Account 364, negative 10% for Account 366, and negative 15% for Account 369. Tr. vol. 15, 792. Witness McCullar expressed concern with the Company's historic net salvage ratios calculated in the Depreciation Study. *Id.* at 794-95. Specifically, witness McCullar took issue with using a net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator. *Id.* Witness McCullar explained that due to inflation the amounts in the numerator and denominator of the net salvage ratio are at different price levels. *Id.* at 795. Witness

McCullar noted that five other jurisdictions have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future net salvage percentages that recognize the time value of cost of removal due to inflation. Tr. vol. 16, 287-88.

In response witness Spanos testified that witness McCullar's proposal is not consistent with the Commission's decision in Sub 1146 and is unsupported by the record. *Id.* at 286. Witness McCullar supported her treatment of Accounts 364, 366, and 369 by arguing against including future inflation in net salvage estimates. *Id.* at 285. Witness McCullar also noted that five other jurisdictions have removed the escalation of estimated future terminal net salvage costs. Tr. vol. 15, 795-98. As witness Spanos previously testified, the Commission has already decided against witness McCullar's position on this concept and found that the Company's approach was widely supported. Overall, while witness McCullar's proposals for these accounts does not have as significant an impact as her proposals for other accounts, she did not provide any statistical basis for her proposal. *Id.* The only analytical method witness McCullar provided in support of her proposal was a comparison of the net salvage costs included in the proposed depreciation rates to the amount of net salvage DEP has incurred, on average, over the past five years. *Id.* at 294. This type of analysis does not provide a reasonable basis to estimate net salvage. Additionally, witness Spanos testified that NARUC and Wolf and Fitch do not support witness McCullar's approach for mass property accounts, and further stated that the Company is unaware of any authoritative texts that support witness McCullar's analysis. *Id.* at 293-95.

Witness Spanos was also asked on cross-examination about the net salvage calculation in an Atmos Energy rate proceeding in Kansas in which witness McCullar testified. Public Staff Spanos Cross-Examination Ex. 3. This testimony did not undermine witness Spanos' position on net salvage, however, because it was clear from the face of the order in that proceeding that the Kansas Commission explicitly rejected a proposed negative salvage calculation based on a "recent history" approach similar to that offered by witness McCullar in this case.

Considering all of the evidence, the Commission finds and concludes that the Company's proposed future net salvage rates for mass property Accounts 364, 366, and 369 are just and reasonable, appropriate for use in this case, and are adopted.

Service Life for AMI Meters

DEP requested a 15-year depreciation life for AMI meters. As explained by witness Spanos, a 15-S2.5 survivor curve was recommended by DEC for AMI meters, which the Commission previously approved in Sub 1146. Tr. vol. 16 at 297. This estimate was consistent with the manufacturer's recommendation for the physical life of the AMI meters and accounted for alternative reasons for retirement such as damage or obsolescence. *Id.*

Public Staff witness McCullar recommended a 17-year service life for AMI meters. Tr. vol. 15, 792. Witness McCullar testified that a 17-year life is in the middle of the manufacturer's range, is a reasonable estimate based on the manufacturer's expected life of the AMI meters, and is fair to the Company and the ratepayer. *Id.* at 791-92.

In response witness Spanos pointed out that the Commission approved the 15- year service life for AMI meters in the 2018 DEC Rate Order. Tr. vol. 16, 296-98. DEP used a 15-year average service life in its previous depreciation study in Sub 1142. *Id*. at 296. In the 2018 DEC Rate Order, the Commission adopted the 15-year average service life. *Id.* at 297. Moreover, DEC's cost-benefit analysis for AMI meters was based on a 15-year average service life and the Commission had specifically requested that such analysis include the "cost of replacing AMI meters at the end of their 15-year useful life."

Witness McCullar has not provided any new evidence in the instant case that supports changing the 15-year average service life previously approved by the Commission. Witness McCullar's arguments are almost identical to those she presented in Sub 1146, which were not persuasive to the Commission. Additionally, witness McCullar simply took the mid-range of the manufacturer's life without considering issues like technological obsolescence. In that regard, witness McCullar made no attempt to distinguish the type of asset, which is a critical consideration when there is limited historical experience.

Based on all the evidence the Commission finds and concludes that the Company's request to establish a 15-year average service life for AMI meters is just and reasonable and appropriate for use in this case.

Amortization Period for General Plant – Accounts 391 and 397

The Commission finds that DEP did not present sufficient evidence in this proceeding to justify reducing the current approved amortization period for the two general plant accounts in question. While consistent treatment of these accounts between DEC and DEP is one consideration, there may be valid reasons for maintaining different amortization periods between the companies for these accounts. As noted by witness Spanos, one of the primary benefits of general plant amortization is to reduce accounting expenses associated with tracking the retirement of individual assets. However, as noted by witness McCullar, DEP no longer keeps detailed historic life records for these amortized accounts therefore, there is not sufficient data in this proceeding that the original amortization periods, which were consistent with the historic life data available in the previous docket, are unreasonable.

For purposes of this proceeding, the Commission believes it is appropriate for DEP to continue to use the 20-year amortization period for Accounts 391 and 397 that were approved at the time these accounts were switched from depreciation accounts to amortization accounts. To the extent DEP identifies adjustments needed to adjust the remaining life calculation and update the reserve allocation adjustment for amortization for each account to reflect the use of a 20-year amortization period, the Commission directs DEP to identify these adjustments in its compliance filing.

Conclusions

In sum, and based on the foregoing conclusions, the Commission finds that DEP shall: (1) continue to use a 10% contingency in the estimate of future terminal net salvage costs; (2) use its proposed future net salvage rates for mass property Accounts 364, 366, and 369; (3) use an average service life of 15 years for new AMI meters being deployed; and (4) continue to use a 20-year amortization for Accounts 391 and 397. The Commission further concludes that except where specifically addressed in this Order, the remaining depreciation rates as proposed by DEP in this case shall be used in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

Early Retirement of Coal Plants

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses De May and Spanos, Public Staff witnesses McCullar, Dorgan, and Metz, and FPWC witness Brunault; and the entire record in this proceeding.

Summary of the Evidence

In its new depreciation study DEP shortened the life span estimates of Mayo Unit 1 and Roxboro Units 3 and 4 from those currently approved. DEP witness Spanos explained that the life span estimates for DEP's production facilities are based on informed judgment, incorporating factors for each facility such as the technology of the facility, management plans and outlook for the facility, and estimates for similar facilities at other utilities. Tr. vol. 11, 218. He further noted that the Asheville coal units 1 and 2 that were scheduled for retirement in 2019 will continue to be recovered through December 2027. *Id.* Witness Spanos stated that the revised life spans are reasonable because, in recent years, original life spans for steam production facilities have been shortened due to unit efficiencies and operating costs (driven in part by environmental regulations). *Id.* at 299.

Public Staff witness McCullar calculated depreciation rates using the retirement dates from the previous depreciation study. Tr. vol. 16, 806. Public Staff witness Dorgan recommended that witness McCullar restore the depreciation rate of Mayo Unit 1 and Roxboro Units 3 and 4 to the depreciation rate approved in Sub 1142, for the following reasons: (1) although the Company has stated in its testimony that it intends to retire these plants, it has not presently done so; (2) the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case; and (3) given operational concerns, the Public Staff believes it is appropriate to continue this consistent treatment of retired plants. Tr. vol. 15, 734.

Public Staff witness Metz testified that DEP's retirement dates proposed in this case are earlier than those shown in DEP's 2018 IRP and its 2019 Update, filed in Docket No. E-100, Sub 157. Witness Metz further testified he believed that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements.

FPWC witness Brunault recommended that the lifespans of Mayo Unit 1 and Roxboro Units 3 and 4 be consistent with the retirement dates in DEP's 2019 IRP Update Report filed with the Commission on September 3, 2019, in Docket No. E-100, Sub 157, rather than the earlier dates utilized in the 2018 Depreciation Study. Tr. vol. 14, 52-56.

In rebuttal DEP witness De May noted the ongoing pressure to meet aggressive carbon reduction and emissions goals and to adapt further climate change-related policymaking. Tr. vol. 11, 777.

DEP witness Spanos testified that the Uniform System of Accounts (USOA) requires that depreciation recover the costs of an asset over its service life. Tr. vol. 16, 300. Recovering costs after an asset is retired results in intergenerational inequity because future customers, who will not receive service from the retired asset, are forced to bear the costs for an asset that is already retired. *Id.* Witness Spanos explained that Public Staff's proposal will result in intergenerational inequity because it will result in DEP recovering a portion of the costs of Mayo Unit 1 and Roxboro Units 3 and 4 after they are retired. *Id.* at 300-02. Witness Spanos also challenged witness Dorgan's other justifications. *Id.* at 301-02. He further stated that the Public Staff's proposal will, by design, result in intergenerational inequity.

On cross-examination, witness Spanos accepted that under N.C.G.S. § 62-35 the Commission sets the rules for DEP's North Carolina retail accounting practices. Witness Spanos further agreed that Commission Rule R8-27 currently provides for the FERC Uniform System of Accounts to be the default system of accounts for electric utilities that are regulated by the Commission. Finally, witness Spanos testified that the Commission has historically provided for undepreciated balances to be recovered from customers after assets have been retired. During cross-examination witness Spanos was presented with two examples in which remaining unrecovered depreciation of DEP's plants were recovered from ratepayers in the years after they were retired.

Discussion and Conclusions

Based on the foregoing and the record, the Commission finds that it is appropriate to require DEP to continue to depreciate the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants based upon their remaining useful life as approved in Sub 1142. In reaching this conclusion, the Commission gives significant weight to the testimony of

Public Staff witnesses Dorgan and Metz. The Commission agrees with witness Metz that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements. Moreover, the Commission notes that the Company did not file the requested accelerated depreciation for the plants in either its 2018 IRP or the 2019 Update.

Witness Dorgan stated that the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case. The Commission determines that this methodology is supported by the examples the Public Staff provided during cross-examination of Company witness Spanos. When presented with Public Staff Doss Spanos Rebuttal Cross-Examination Exhibit No. 2, witness Spanos affirmed that Duke Energy requested the same methodology proposed by the Public Staff in this proceeding in Sub 1142. Witness Spanos further confirmed this same treatment was approved by the Commission in Docket No. E-2, Sub 1023 for retirement of DEP's Cape Fear, Lee, Robinson, Weatherspoon, and Morehead City coal plants.

The Commission has consistently strived to balance allowing utility companies to receive full recovery of early retirement costs while not unduly burdening ratepayers. In the present case the Company's proposed accelerated depreciation would unduly burden the ratepayers for the next several years as they would be paying more for electric service. DEP on the other hand would be recovering the plants' costs more quickly than last projected in its IRP, which is where generation mix and service lives of DEP's assets are fully vetted. As DEP has not updated its IRP for the proposed service life changes of the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants, the Commission and other parties have not had the chance to fully examine the issue within the confines of an IRP. For these reasons, the Commission finds the Company's approach to be unbalanced.

Therefore, in light of the foregoing, the Commission concludes that the depreciation for the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants should be based upon the remaining life as presented in Sub 1142 and, upon actual retirement of each unit, the remaining undepreciated net book value placed in a regulatory asset account to be amortized over an appropriate period determined in a future rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

Coal and Nuclear Fleet Investments

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Turner and Henderson, Public Staff witness Metz, NC WARN witness Powers, and Sierra Club witness Wilson; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Company witness Turner described the Company's fossil/hydro/solar (FHO) generation assets and provided operational performance results for those assets during the test period. Tr. vol. 11, 970-71, 975-77. Witness Turner testified to the major FHO capital additions DEP has completed since the previous rate case, explaining that the Company has made significant investments in the coal fleet to meet environmental regulations to allow for the continued operation of active plants. *Id.* at 972. Witness Turner also discussed the addition of the Asheville CC Project units, and the retirement of the two Asheville Steam Electric Generating Plant units, anticipated by the end of 2019. In addition, she explained that the Asheville CC Project, for which DEP received a certificate of public convenience and necessity (CPCN) from the Commission in Docket No. E-2, Sub 1089 (Asheville CPCN Order), features state-of-the-art technology for increased efficiency and reduced emissions. *Id.* at 971-72. Witness Turner testified that the Company prudently incurred all of these costs and addressed the key drivers impacting O&M expenses. *Id.* at 973-75. Furthermore, she stated that these investments would be used and useful in providing electric service by the capital cutoff date, and benefit customers, as they have enabled DEP to continue to provide safe, efficient, and reliable service at least reasonable cost. They have also reduced the Company's environmental footprint by adding state-of-the-art technology for reducing emissions, retiring older facilities that lacked environmental equipment and were not economically positioned for needed capital expenditures, and expanding the use of natural gas generation at a time when the natural gas market is providing low prices. *Id*. at 973-74.

Company witness Henderson described DEP's nuclear generation assets and capital additions to the nuclear fleet made to enhance safety, address regulatory requirements, and preserve performance and reliability of these plants throughout their extended life operations. Tr. vol. 11, 127-32. Witness Henderson testified that these capital additions and enhancements are used and useful in safely and efficiently providing reliable service to DEP customers and position the Company to maintain the high levels of operational safety, efficiency and reliability reflected in the fleet's performance results. *Id*. at 132. Witness Henderson also discussed key drivers impacting nuclear O&M costs, including inflationary pressure on labor and materials, and the Company's strategy for mitigating that pressure. Witness Henderson noted that customers will continue to benefit from the strong performance of DEP's nuclear fleet through lower fuel costs. *Id*. at 132-34. Witness Henderson described DEP's current status with respect to compliance with Nuclear Regulatory Commission (NRC) requirements. *Id*. at 135-39. Finally, he discussed the high performance of the Company's nuclear fleet during the test period and the steps DEP has taken to increase efficiencies in nuclear operations. *Id*. at 139-42.

Public Staff Testimony

Public Staff witness Metz discussed his review of DEP's capital additions to both the FHO and nuclear fleets, in which he looked at multiple aspects of capital spend to evaluate them for reasonableness and prudence, as well as whether the asset or result of the capital investment was used and useful. Witness Metz noted that his investigation included, in addition to reviewing prefiled direct testimony, an audit of specific expenditures, initial and follow-up discovery, teleconferences between and interviews with the Company and Public Staff, site visits, and review of the overall projects with Company management. Tr. vol. 15, 821-22. Witness Metz discussed the status of the Asheville CC Project and the repairs that had been required at one of the steam turbine components of that project, concluding that the Company was not at fault for the events necessitating the repairs. *Id*. at 823-24. The Public Staff did not recommend any disallowance of the Company's request for recovery of its capital investments in either its FHO or nuclear fleets based on imprudence. *Id.* at 824.

Sierra Club Testimony

Sierra Club witness Wilson recommended disallowance of all of the Company's FHO capital expenditures made between the Sub 1142 rate case and the current case, based on her contention that the net value of each of the coal units was negative for the 2016-2018 time period, until DEP provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made. In addition, she claimed that DEP did not demonstrate the prudence of its historical capital investments in its coal units. Tr. vol. 15, 42-47, 54, 56. Witness Wilson acknowledged the advancement of the probable retirement dates of certain units based on the Company's updated depreciation study. *Id.* at 36-37. She also acknowledged that retirement of the entire coal fleet at once would likely lead to reliability issues in DEP's service territory. *Id.* at 50.

Based on her projected future energy value of the DEP coal fleet and citing to the Georgia Public Service Commission (Georgia Commission) as having taken similar action, she also recommended that the Commission cap future capital expenditures intended to prolong the lives of these units and require DEP to obtain Commission approval of any expenditure that exceeds the cap before it can be recovered from customers. *Id.* at 47-54. Further, she recommended that the Commission disallow recovery of "ongoing" O&M expenses at DEP's coal units. *Id*. at 57. Witness Wilson also recommended that in future rate cases, DEP be required to demonstrate that its natural gas units are providing positive net value to ratepayers before being granted recovery of capital and O&M costs. *Id*. at 50-54. Finally, she suggested that the used and useful standard could be interpreted to mean that if there was a power plant construction project planned in a prudent manner, that operates at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee, the plant may be found prudent and used, but not economically useful. *Id.* at 55.

On cross-examination witness Wilson agreed that as DEP transitions away from reliance on coal it must nonetheless continue to meet its obligation to provide safe and reliable electric service to customers. *Id.* at 65. Witness Wilson acknowledged that her testimony did not specify any particular project or costs that DEP should not have incurred, did not offer other options that DEP could have chosen instead of incurring any of the costs it seeks to recover now, and that her analysis did not analyze the Company's decisions about coal fleet investments at the time it made those decisions. *Id.* at 98-99. Witness Wilson testified that she was not aware of the North Carolina standard for challenging prudence that requires a party to identify specific instances of imprudence and provide a prudent alternative. *Id.* at 68. Regarding her testimony on the "used and useful" standard, she could not identify any state commission that had adopted her interpretation of that standard. *Id.* at 72.

Witness Wilson also agreed that some coal fleet environmental investments were required whether or not the units continued to operate.*Id.* at 76-77. She testified that she did not analyze whether shutting the units down was a feasible path DEP could have chosen while continuing to meet its service obligations. *Id.* at 77-78. Witness Wilson acknowledged that her analysis did not consider whether it would have been feasible or cost-effective for DEP to retire Mayo or Roxboro Stations rather than make the investments the Company is seeking to recover in this case. *Id.* at 103.

NC WARN Testimony

NC WARN witness Powers recommended disallowance of the Company's costs for the Asheville CC Project. Tr. vol. 15, 885. Witness Powers claimed that DEP's investments in this project were not reasonably and prudently incurred based on his contention that the project was not needed. *Id*. at 886. Specifically, he asserted that DEP could have avoided investing in the Asheville CC Project by relying on regional merchant combined cycle, hydroelectric plants, and the addition of battery storage at existing North Carolina solar facilities. *Id*. at 882-885. Finally, he compared his estimation of the production cost at the Asheville CC Project to approximations of production costs for hydroelectric and battery storage resources. *Id*. at 881-84.

DEP Rebuttal Testimony

In rebuttal witness Turner addressed the testimony and recommendations of witnesses Wilson and Powers. Tr. vol. 11, 989-991. She explained that such contentions fail to recognize the full picture of how DEP dispatches its coal fleet to maximize value for customers. Witness Turner noted that witness Wilson's study did not appear to account for the requirement of day-ahead planning reserves and explained that capacity must be online or available within 10 minutes. Further, she stated that a coal unit will provide energy and capacity during the peak, and that if a needed coal unit is not online then the Company must start additional combustion turbines or purchase energy and capacity from the market, if capacity is available during such a time. *Id*. at 991-92.

Witness Turner also testified that witness Wilson's forward-looking analysis of the coal fleet is not a valid exercise for a general rate case. *Id.* at 992. Witness Turner noted that witness Wilson did not explain how her proposed cap on future coal fleet investments would be determined and clarified that these investments were made to maximize the remaining useful life of the units. Witness Turner stated that the Company cannot recover such costs from customers unless and until the Commission permits it to do so. Finally, she clarified that estimates of future capital investments are not relevant to this proceeding. *Id.* at 992-93.

Witness Turner also testified that witness Powers did not offer a credible and specific explanation of how DEP could have replaced the reliable generation provided by the Asheville CC Project and did not otherwise credibly challenge the Company's reasonable and prudent decision to invest in this project. In addition, she noted that NC WARN ignored additional factors that supported the reasonableness and prudence of this investment, including the Mountain Energy Act, which specifically contemplated DEP's construction of a new natural gas fired generating facility at the Asheville site, and the Commission's Asheville CPCN Order which determined that the project was needed. *Id*. at 994-95.

Witness Turner also explained that DEP did not conduct a comprehensive retirement analysis regarding investment in environmental compliance projects at Roxboro Station but performed a similar analysis for Mayo Station, which indicated in all scenarios studied that it was not economical for customers to retire and replace Mayo Station with environmental investments. As a result – and given that Mayo Station has a 700 MW capacity – it was also not likely to be economical for Roxboro Station, which has a capacity of 2400 MW. In addition, witness Turner stated that the energy produced by these stations was required for DEP to reliably serve its customers, and DEP could not have replaced these resources in the period of time available. *Id.* at 1002-03, 1005. Witness Turner also explained that each of the scenarios evaluated in the Mayo study considered natural gas as the alternative, because natural gas was determined to be the most economical type of generation resource as shown in the Company's most recent IRP at that time. *Id.* at 1003-04.

During redirect examination witness Turner clarified that the portion of total investments DEP made at Roxboro and Mayo Stations related to environmental compliance exceeded the portion for maintenance capital investments at those stations. *Id.* at 1006-07. In addition, she confirmed that the Company would have had to make approximately half of the environmental investments even if it retired these units early, in order to remain compliant with environmental regulations while the units were still operating. *Id.* at 1007. Witness Turner also described the disciplined process DEP uses to evaluate whether to make investments in its coal fleet and confirmed that the Company operates and makes investment decisions based on information available at the time. Witness Turner also described how the Company's investments in its coal fleet have benefitted customers, explaining for example that while capacity factors for the coal fleet have declined in recent years, these units' capacity is critical to the DEP system as evidenced by the 94% capacity factor at the Roxboro and Mayo units during early January 2018. Witness Turner confirmed that DEP's coal fleet investments have allowed the Company to remain environmentally compliant and to continue to provide safe and reliable service to customers. *Id.* at 1008-10. She testified that the updated plans for DEP's coal fleet presented in the Company's 2020 IRP are consistent with its proposal in this case to accelerate the depreciable lives of some of those units. *Id*. at 1010-11.

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission finds and concludes that the costs associated with the Company's investments in its coal fleet were reasonably and prudently incurred and should be recovered. The Commission further finds and concludes that based on this record the Sierra Club's additional recommendations to limit the Company's future investments in its coal and natural gas units should not be adopted at this time. Finally, the Commission finds and concludes that the costs associated with the Company's investments in its nuclear generating fleet were reasonably and prudently incurred and should be recovered.

When setting just and reasonable rates the Commission must determine whether costs incurred by the utility were prudently incurred, which involves an examination of whether the utility's actions, inactions, or decisions to incur costs were reasonable based on what it knew or reasonably should have known at the time the actions, inactions, or decision to incur costs were made. When challenging prudence the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. Detailed proof or analysis must also be provided. Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Electric Rates and Charges*, Docket No. E-2, Sub 537, 78 N.C.U.C. Orders & Decisions 238, 251-52 (Aug. 5, 1988) (*Harris Order*), *reversed in part*, *and remanded on other ground*, *Utilities Commission v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production if they dispute an aspect of the utility's prima facie case. *See, e.g., State ex rel. Utils. Comm'n. v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Bent Creek*). If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility, in accordance with N.C.G.S. § 62-134(c).

The Commission gives substantial weight to the testimony of Company witness Turner regarding the prudency of the costs of DEP's investments in its coal fleet. Witness Turner explained in detail how the Company prudently determined that these investments were needed to maintain DEP's remaining active coal units to continue to provide safe, reliable, and cost-effective electric service to customers. He explained that a significant portion of these costs were required under environmental law or regulation regardless of whether the Company continued to run the units and that a large portion of the remaining costs were incurred to maintain compliance with environmental requirements to continue to operate the units. Regarding the Asheville CC Project, witness Turner presented convincing evidence in rebuttal and at the hearing regarding the rationale for this investment, which was made pursuant to the Mountain Energy Act and which the Commission found was needed in Docket No. E-2, Sub 1089. As discussed elsewhere in this Order, the Asheville CC Project is complete, placed in service, and available for economic dispatch. Further, no party has offered concrete, specific evidence to contradict DEP's determination that it needed to continue to operate these units to serve customers or has met the burden of production to challenge the Company's specific coal fleet investments.

Sierra Club witness Wilson's recommended disallowance, as she admitted, is not specific to any particular cost, neither does Sierra Club offer any prudent alternative that DEP could have chosen. Witness Wilson admitted that retiring the coal fleet all at once would likely result in reliability issues yet did not identify any other alternatives available to the Company. Regarding NC WARN's recommendation, other than the Asheville CC Project in general, witness Powers did not identify any specific costs as being imprudently incurred. In addition, the alternatives suggested by NC WARN – merchant generation purchases, solar plus storage, and hydroelectric generation – are not supported by any evidence suggesting that these were feasible options for the Company. No witness conducted an independent analysis using the information available at the time the Company's investment decisions were made to present evidence supporting a finding that DEP could have made another prudent choice. The evidence instead demonstrates that the Company made the best investment decisions it could with the information available at the time.

Moreover, the Commission finds persuasive witness Turner's rebuttal of witness Wilson's economic value analysis, which did not consider either the capacity value provided by DEP's coal fleet or how the Company dispatches its system as a whole on a daily basis. Isolating costs invested in and the value of energy produced by a particular station on an annual basis does not accurately represent the value of the coal fleet. As witness Turner testified, even units with declining capacity factors are still needed during times of high demand. For similar reasons, and because DEP must still invest in a unit to keep it available during high demand periods, the Commission does not find witness Wilson's recommendation that the Company consider operating its units seasonally to be reasonable. Finally, the Commission does not accept witness Wilson's interpretation of the term "useful" in the used and useful standard. Her reading contemplates finding an asset not to be useful when it was planned prudently and was impacted by changes outside the utility's control, which is not an interpretation that has been adopted by this Commission.

Witness Wilson quantified her disallowance recommendation on the contention that DEP did not present evidence of the value of the investments at the time they were made. However, as witness Wilson's hearing testimony made clear, she ignored evidence in the form of the 2016 Mayo Station retirement study pertaining directly to this issue. As shown by witness Turner's testimony, the Company conducted an exhaustive study of continued investments in Mayo Station, as well as economic analyses of other coal fleet investments, and relied on the results of those studies to proceed with the investments it is seeking to recover. The Commission therefore concludes that Sierra Club's assertion regarding a lack of evidence is not supported by the record.

The Commission also declines to accept witness Wilson's recommendation to limit the Company's future investments in its coal fleet. Such a limitation is not necessary as the Company is not able to recover any future capital investments before seeking and obtaining the Commission's approval in a future proceeding. Further, as witness Wilson recognized, North Carolina uses a historical test year as the basis for evaluating just and reasonable rates, which is not consistent with a prospective limit on capital expenditures.

Finally, no party recommended any disallowance of the Company's request for recovery of its capital investments in its nuclear fleet based on unreasonableness or imprudence. As a result, and based on the uncontroverted testimony and the record, the Commission finds and concludes that the costs associated with the Company's investments in its nuclear generating fleet were reasonably and prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-23

CCR Cost Recovery

The evidence supporting these findings of fact is found in the verified Application, and Form E-1; the CCR Settlement; the testimony and exhibits of the expert witnesses in both the present rate case and the 2018 DEP rate case, including the testimony and exhibits of DEP witnesses De May, Bednarcik, Wells, Williams, Bonaparte, Lioy, Doss, Riley, Spanos, and Fetter, Public Staff witnesses Lucas, Maness, Garrett, and Moore, AGO witness Hart, Sierra Club witness Quarles, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness Bednarcik

Witness Bednarcik provided an overview of the federal and state regulatory requirements applicable to DEP's coal ash basins and landfills, including the CCR Rule and CAMA. Witness Bednarcik testified that all of the coal ash remediation actions taken by DEP for which it is seeking cost recovery were required by applicable statutes and regulations and were performed in a prudent and reasonable manner. Tr. vol. 12, 31-33.

Witness Bednarcik explained the closure options available for the Company's low-risk impoundments, including the Company's original plans to close those basins by cap-in-place. With assistance from experienced, professional engineering firms, the Company developed and submitted Closure Options Analysis Reports (COA Reports) to DEQ in fourth quarter of 2018 for the four sites. *Id.* at 37-41. On April 1, 2019, DEQ ordered Duke Energy to excavate all remaining coal ash impoundments in North Carolina, including the low risk impoundments at Mayo and Roxboro. *Id.* at 42. With the exception of preliminary closure plan development, the Company had not begun implementing cap-in-place closure at any of the sites covered by the order. *Id.* Next, witness Bednarcik discussed the unique closure activities that the Company has undertaken at each of its sites, itemizing the associated costs thru June 2019 related to compliance and closure of its CCR basins: Mayo ($22,520,499), Roxboro ($16,845,265), Asheville ($99,274,167), Sutton ($102,560,125), Cape Fear ($41,690,655), H.F. Lee ($86,609,666), Weatherspoon ($25,674,837), and Robinson ($20,762,298). *Id.* at 45-50, 54-55.

In Witness Bednarcik further testified that in 2014 Duke Energy executed contracts with Charah, LLC (Charah), to dispose of coal ash from DEC's Riverbend plant and DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants. She stated that the contracts required Duke to provide a minimum amount of coal ash and that due to changing circumstances caused by CAMA amendments, Duke did not provide the minimum amount of coal ash to Charah. *Id.* at 51-52. As a result, Duke incurred a fulfillment charge of $80 million, of which $33,670,054 had been allocated to DEP. Witness Bednarcik testified that the Company could not have foreseen the CAMA amendment, and therefore acted reasonably and prudently when it executed the Charah contract, thereby authorizing it to acquire the necessary mines and develop infrastructure needed to transport and store the Company's coal ash.

Public Staff

Witness Lucas

Public Staff witness Lucas discussed in his testimony[2] a set of historical documents that he testified showed "an evolving body of scientific knowledge over more than 50 years concerning the risks of environmental contamination resulting from storing coal ash in unlined impoundments, and alternative methods of coal ash management." Tr. vol. 15, 1477-78. According to witness Lucas these documents demonstrated that, "by the early 1980s, the electric generating industry knew or should have known that the wet storage of CCR in unlined surface impoundments posed a serious risk to the quality of surrounding groundwater and surface water." *Id.* at 1478. He argued that given the state of knowledge at the time, "DEP should have installed comprehensive groundwater monitoring well networks in the 1980s to determine if the risk was materializing." *Id.* at 1480-81. Witness Lucas testified that DEP has accumulated significant environmental

[2] The live testimony of witnesses Bednarcik, Wells, Williams, Hart, Quarles, Wilson, Garrett, Moore, Riley, Junis, and Maness in Docket No. E-7, Sub 1214 was copied into the record in the current docket as if given orally from the stand, pursuant to the September 28, 2020 Amended Joint Stipulation Regarding Admission of Certain Live Testimony and Exhibits (Amended Stipulation) entered into by DEP, the Public Staff, the Attorney General's Office, and the Sierra Club. The Amended Stipulation stated the following: "The Stipulating Parties recognize that Public Staff witness Junis appeared in the DE Carolinas case, but is not appearing in the DE Progress case, and that his place in the DE Progress case is being assumed by Public Staff witness Jay Lucas. Accordingly, in this instance, the "same" witness as Charles Junis in the DE Progress case is understood to be Public Staff witness Lucas." Amended Stipulation at 3, n 2. Therefore, during the hearing, witness Lucas adopted the live testimony of Public Staff witness Junis in Docket No. E-7, Sub 1214, and witness Maness' live testimony in Docket No. E-7, Sub 1214 was likewise copied into the record. Tr. vol. 15, 1633-34. Citations in this Order to Tr. vol. 15, pages 1639-1817 reference the stipulated live testimony from Docket No. E-7, Sub 1214 of witnesses Junis and Maness.

violations associated with its coal ash impoundments, including unauthorized seeps in violation of its NPDES permits and 7,411 groundwater exceedances in violation of the state's 2L rules. Regarding seeps, he explained that while almost all earthen dams have seeps, DEP's dams impound coal ash wastewater, which cannot be lawfully discharged without a permit. *Id.* at 1485-88. He also explained that "engineered" or "constructed" seeps are those that were deliberately constructed. *Id.* at 1485. Witness Lucas described Special Orders by Consent (SOCs) entered into between DEP and DEQ for seeps at the Asheville, Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon plants.

Witness Lucas testified that the deliberately constructed seeps have been included in the Company's renewed or modified NPDES permits but argued that including these seeps in DEP's permits "does not retroactively condone them." *Id.* at 1487. Witness Lucas stated that despite the knowledge that groundwater monitoring is "necessary to provide convincing proof of a safe disposal practice," DEP did not begin groundwater monitoring at some of its facilities until decades later. *Id*. at 1491-92. Witness Lucas testified that it is notable that the Company's number of groundwater standard violations has increased by 4,554, or 159%, since his testimony in the last DEP rate case. *Id*. at 1508.

Witness Lucas argued that while the Company calls such costs "compliance costs" for meeting the requirements of CAMA and the CCR Rule, "they also reflect DEP's non-compliance with longstanding environmental regulations." *Id*. at 1494. Witness Lucas opined that the evidence shows DEP would have incurred substantial corrective action costs under the state's 2L rules even in the absence of CAMA and the CCR Rule. . He stated, however, that there were instances in which DEP's actions were prudent, that separating out the imprudent costs would be complex, and that the calculation of some costs of imprudence would be speculative. *Id*. at 1506-08, 1821-23. Witness Lucas concluded that "[d]ue to its environmental violations, DEP has a great deal of culpability for the compliance costs related to remediation and ash basin and storage unit closures, and would likely have incurred substantial coal ash corrective action costs even without the CCR Rule and CAMA, whereas ratepayers are not culpable at all for those costs." *Id*. at 1510. Therefore the Public Staff recommended an equitable sharing, with 50% of the CCR costs being paid by shareholders and 50% by ratepayers. *See also id*. at 1761-62.

Witness Lucas summarized the details of the 2019 Settlement Agreement, reached by DEC, DEP, DEQ, and several environmental parties, which addressed CCR impoundments at DEP's Mayo and Roxboro plants and DEC's Allen, Belews Creek, Cliffside, and Marshall plants, and which, among other things requires Duke Energy to excavate a majority of the coal ash and place it in a lined landfill. The 2019 Settlement Agreement also indicated some relief for the closure deadlines for the Buck, H.F. Lee, and Cape Fear plants.

Witness Lucas also testified that the Public Staff's recommended disallowance of the costs to provide bottled water, water connections to municipal or county systems, and water treatment systems; for the period of September 2017 through December 2019, the costs amounted to $395,005, $1,087,612, and 2,774,583, respectively, on a system basis. Tr. vol. 15, 1503-05. In his supplemental testimony, witness Lucas updated the

Public Staff's position to include the costs of municipal water supplies and water filtration systems that the Company incurred in January and February 2020. *Id.* at 1529-30.

Witnesses Garrett and Moore

Witnesses Garrett and Moore, each principals in and founding members of Garrett & Moore, Inc., which provides environmental engineering and consulting services to power and waste industries, proposed three distinct prudence-based disallowances to the Company's CCR costs.

First, witness Garrett proposed a disallowance of $33,670,054 which represented DEP's allocation of the fulfillment fee the Company paid to Charah related to the disposal of ash from the Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants at the Brickhaven structural fill site. Tr. vol. 15, 1222, 1235-36. Witness Garrett also testified that he believed any consideration of fees paid for land acquisition at the Sanford Mine pursuant to the Charah Master Contract should be excluded because no ash was ever transferred from any DEP site to the Sanford mine. *Id.* at 1236.

Second, witness Garrett proposed a disallowance of $50,238,630 related to the hauling costs for disposal of ash from the Asheville plant to the R&B landfill in Homer, Georgia. *Id.* at 1222, 1252. In support of his recommended disallowance, he argued that there were two lower cost alternatives to disposal at the R&B landfill: (1) transportation of ash to Cliffside; and (2) depositing ash in an onsite landfill. *See also id.* at 1261-62.

Third, witness Moore proposed a disallowance of $130,348,392, representing a portion of the costs related to the beneficiation units at the H.F. Lee and Cape Fear sites. *Id.* at 1183. Specifically, witness Moore testified that the costs incurred by subcontractor Zachry Industrial Inc. (Zachry) for Engineering, Procurement, and Construction (EPC) at the Cape Fear and H.F. Lee beneficiation sites were not reasonable and prudent because they were higher than the estimate for each project that was included in contractor The SEFA Group, Inc.'s (SEFA) response to the Company's Request for Information (RFI). *Id*. at 1195. Witness Moore testified to many other steps that the Company should have taken to mitigate the high cost, including re-bidding the contract, entering into three separate construction contracts, obtaining an amendment to CAMA, or obtaining guidance from DEQ. *Id.* at 1205-06.

Witnesses Garrett and Moore otherwise testified that they found the Company's requested recovery for CCR costs incurred at the Mayo, Roxboro, Sutton, and Robinson plants to be reasonably and prudently incurred. *Id*. at 1184-85,1264-65.

Witness Maness

Witness Maness discussed the three coal ash cost adjustments being proposed by the Public Staff: (1) the disallowances recommended by witnesses Lucas, Moore and Garrett; (2) an amortization period of 25 years; and (3) the reversal of DEP's inclusion of coal ash costs in rate base.

Witness Maness testified that the Public Staff believes there should be an equitable sharing of the coal ash costs between ratepayers and shareholders. Tr. vol. 15, 1560-65, 1579. He explained that an equitable sharing can be achieved by, first, excluding the coal ash costs from inclusion in DEP's rate base and, second, using a longer amortization period. Witness Maness testified that the five-year amortization period proposed by DEP is too short. He stated that the CCRs are the result of decades of generating electricity by coal and that associated costs should be amortized over a similarly lengthy period. The Public Staff, therefore, recommends an amortization period of 25 years. *Id.* at 1560-61, 1627. Witness Maness also gave several reasons why, independent of culpability, the magnitude and general nature of the CCR costs in this case justified equitable sharing. *Id.* at 1563-65.

With respect to DEP's future coal ash costs, witness Maness testified that the Public Staff agrees that DEP should be allowed to defer its future costs in a regulatory asset and accrue a return on the deferred balance at the net-of-tax overall return authorized by the Commission for DEP during the deferral period. *Id*. at 1587-89.

AGO

AGO Witness Hart

In the current rate case witness Hart discussed the CCR Rule, CAMA, the 2L rules, and other environmental guidelines applicable to coal ash basins. Witness Hart testified that unlined coal ash basins cause groundwater contamination. Tr. vol. 13, 570-72. He explained that the metals present in the coal ash leach out of the ash, enter a dissolved state, and become coal ash "leachate," and that because a hydraulic head is maintained in the basin the metals-laden water in the basin migrates downward into underlying soil. *Id*. at 575-86. Witness Hart discussed several industry and government studies and reports, similar to those noted by other witnesses, *see id.* at 588-602, that he opined placed the electric utility industry on notice of the potential leaching of coal ash metals into groundwater.

Witness Hart provided the details of the coal ash basins and groundwater monitoring at each of DEP's coal plants. In addition, he included graphs for each plant showing the most prominent coal ash constituents. *Id*. at 624-85. Witness Hart concluded that prior to the Dan River coal ash spill DEP did not take reasonable and prudent actions to address groundwater contamination at its coal ash basins and to close the basins. *Id.* at 685-93. Witness Hart testified that DEC's inaction increased its present coal ash remediation costs because the Dan River spill prompted accelerated remediation actions, which are always more costly. Witness Hart stated that earlier prudent action by DEP would have resulted in cost recovery while the coal plants were still in use, and beginning in 1992, 1996, or 2009, DEP's system coal ash closure costs would have been reduced by $291 million, $275 million, or $218 million, respectively. *Id.* at 693-703.

Sierra Club

Witness Quarles

Sierra Club witness Mark Quarles previously testified in Sub 1142 about coal ash and evaluated the methods by which DEP proposed to close existing CCR surface impoundments in-place by leaving wastes in existing disposal areas (i.e., "closure-in-place") at its Mayo and Roxboro coal plants. That testimony evaluated whether and opined that the Company could not meet the closure-in-place performance standards established by EPA in its CCR Rule due to site characteristics and hydrogeologic conditions at the Mayo and Roxboro sites, and that groundwater contamination would continue into the foreseeable future.

In the current rate case witness Quarles focused in his testimony on "determining *when* the Company knew or should have known that groundwater or surface water contamination was likely due to storage and disposal of CCRs in unlined areas located near — and even sometimes within — rivers and streams and where the ash is saturated with groundwater." Tr. vol. 12, 591. Witness Quarles also concluded that DEP's total coal ash clean-up costs could have been lower if the Company had switched to dry disposal in lined landfills sooner and testified that the risks of groundwater contamination from unlined coal ash ponds were understood as early as the late 1970s. *Id.* at 594.

Witness Quarles testified to the history of DEP's use of unlined ponds at each plant, noting that DEP constructed surface impoundments from the 1950s through 1980s and expanded some as recently as 2001 (Weatherspoon) and 2002 (Robinson). Witness Quarles also testified that DEP began "required" groundwater monitoring at Sutton in 1984, Roxboro in 1986, and Weatherspoon in 1989. The earliest instances of "voluntary" monitoring were at Cape Fear and H.F. Lee in 2007 and Mayo in 2008. Some of these sites went unmonitored for over 50 years. Witness Quarles opined that this decades-long operation without monitoring was unreasonable, given the known risks and that the Company itself knew of leaching at Sutton in the early 1980s. *Id.* at 606.

In addition to DEP's knowledge of the leaching at Sutton, Witness Quarles pointed to several other records which showed the Company investigated potential groundwater contamination as early as the 1970s, including a groundwater study at Sutton which concluded that the new basin should be built with a liner and a 1979 study of the Mayo site which evaluated the geologic and hydrologic conditions; that study concluded that "at least a one-foot layer of clay beneath the proposed pond was necessary to protect groundwater, but even with such clay lining, not all metals would be filtered, and the duration of the filtering would be limited." *Id.* at 607-08. Witness Quarles also noted that DEP itself concluded in 2014 that its "coal ash is impacting groundwater at all locations" and that groundwater protection standards had been exceeded for each site for one or more of the following: arsenic, cobalt, lithium, molybdenum, selenium, thallium, and total radium, with migration off-site at several of the sites. *Id.* at 612. "[R]ather than initiating corrective actions to eliminate or mitigate the contamination, Duke Energy companies have responded by purchasing affected properties or providing alternative drinking water sources" including at Sutton and H.F. Lee. *Id.*

For these and other reasons witness Quarles recommended that the Commission conclude that DEP's continued operation of unlined basins after the industry recognized the risks, that operation of unlined coal ash basin after the 1980s, and that the Company's failure to operate adequate groundwater monitoring around its disposal areas until the 2000s, were each unreasonable.

CUCA

Witness O'Donnell

Witness O'Donnell contended that Duke management's specific decisions caused the Dan River spill and cited an early draft of CAMA and statements by legislators to support his contention that Duke's environmental violations caused the General Assembly to enact CAMA, and, therefore, DEP should not be permitted to recover from customers any coal ash costs above those that DEP would have incurred under the CCR Rule. Tr. vol. 14, 168-79.

DEP Rebuttal Testimony

Witness Bednarcik

Witness Bednarcik responded to the Public Staff's recommended 50/50 equitable sharing disallowance, pointing out that the recommendation is not tied to any finding of unreasonableness or imprudence but to culpability for environmental degradation requiring expensive remediation and the enormity of the costs. Tr. vol. 17, 136. She noted Public Staff witness Lucas' admission of the impossibility of conducting a prudency audit of the Company's historical CCR activities, and she stated that the Commission has rejected this equitable sharing approach three times. *Id*. at 137-38.

Witness Bednarcik also responded to the contentions of witnesses Lucas, Hart, and Quarles that the Company's CCR practices lagged behind those of industry, contending that the Company's historical CCR practices were in line with those of industry and similarly situated utilities in neighboring states. *Id.* at 138. In response to the historical documents cited by witnesses Lucas, Hart, and Quarles, witness Bednarcik argued that this "small handful of papers" would not have given a utility adequate reason to change its CCR practices. *Id.* Witness Bednarcik also stated that the intervenor witnesses were viewing these issues "through the filter of a 21st century lens when no such clarity existed in real time." *Id*. at 138-39. Witness Bednarcik also challenged the recoverability of the costs to build new lined impoundments to retire existing coal ash impoundments before the enactment of the CCR Rule and CAMA. *Id.* at 140-43.

Witness Bednarcik addressed the recommended disallowance of AGO witness Hart, arguing against his suggestion that the Company could have reduced costs by beginning closure at an earlier date. Witness Bednarcik stated that it was impossible to predict with any certainty what type of approach DEP would have pursued historically with respect to its coal ash basins given the then-existing regulatory landscape, available technology, evolving industry best practices, and other factors. *Id.* at 142-45. Witness Bednarcik also testified that DEQ instructed DEP as late as 2009 that initiating closure of inactive basins was not necessary. *Id.* at 143-45.

Witness Bednarcik also discussed and rebutted the specific prudence-based and culpability-based disallowances recommended by the Public Staff and AG, including: (1) payment of the fulfillment fee to Charah ($36,670,054), *id.* at 87-89, 92-99; (2) payment of a purported $30.42 per ton cost to transport CCR from the Asheville plant to the R&B landfill in Homer, Georgia ($50,238,630), *id.* at 104-06, 113-16; (3) construction costs at the H.F. Lee and Cape Fear Beneficiation plants ($130,384,392), *id.* at 116-28; (4) expenditures for groundwater extraction and treatment at the Asheville and Sutton plants, as well as the purchase of land at the Mayo plant which allowed the Company to mitigate potential exposure pathways ($1,240,328 on a system basis), *id.* at 132-33; and (5) costs incurred to connect eligible residential properties to permanent water supplies or install and maintain water treatment systems as required by CAMA. *Id.* at 144-45.

Witness Bednarcik also filed supplemental testimony responding to the Commission's July 23, 2020 Order Requiring Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs. Witness Bednarcik discussed the Settlement Agreement the Company reached with DEQ and environmental groups on December 31, 2019, as well as the Company's estimate of the future costs of excavating, rather than capping-in-place, remaining ash at the Company's designated "low-risk" CCR impoundments. *Id.* at 148-55.

Witnesses Wells and Williams

Witnesses Wells and Williams argued that there were flaws in intervenors' theories, namely that they: (1) applied modern environmental standards to historical practices, (2) ignored the discretion afforded to the Company's environmental regulators, and (3) cherry-picked data points to draw unreasonable inferences regarding the Company's knowledge or actions, also dismissing scientific conclusions and regulatory *decisions* that did not fit their narrative. *See* Tr. vol. 19, 140. Witnesses Wells and Williams, together, provided a Company-specific, overall industry, and historical regulatory perspective of coal ash management practices over the past five decades.

Witness Williams, who worked for the EPA for 17 years and served as Director of the Office of Solid Waste until 1988, testified in depth regarding the history of coal ash regulations and the evolution of the CCR Rule. *Id.* at 205-12. She stated that owners and operators of coal ash basins in North Carolina faced significant uncertainty regarding regulatory requirements until adoption of the CCR Rule and CAMA, and based on these uncertainties, owners and operators of coal ash basins acted prudently by waiting for adoption of the CCR Rule and CAMA to take specific actions to upgrade or close coal ash basins. She discussed several factors that compound uncertainty in EPA regulation, and she opined that DEP did not act imprudently by waiting for regulatory clarity so long as it continued to work with regulatory agencies to address site specific environmental risks.

Witness Williams explained that DEP's initial construction and continued use of unlined ash basins even after 2014 was consistent with industry standards and applicable federal and state environmental regulations. Even as late as 2010, when EPA proposed its CCR Rule, witness Williams testified that according to EPA, 74% of existing units were unlined, and 40% of "new" (meaning constructed during the 1990s or thereafter) units were unlined. *Id.* at 422. Witness Wells also explained that DEP's environmental regulators issued permits to DEP which specifically authorized the Company to sluice fly ash and bottom ash to unlined basins and then discharge the sluice water to surface waters after settling occurred. *Id.* at 141-42. He testified that neither the utility industry nor environmental regulators believed that unlined basins posed significant environmental risk, and therefore discontinuing use of unlined impoundments during their useful life was neither prohibited nor even discouraged. *Id.* at 144.

Witness Wells testified that studies performed by EPA, the industry, and DEP in the late 1970s and throughout the 1980s that were applicable to DEP's ash basins consistently demonstrated that harm to groundwater quality from its unlined impoundments was nonexistent or insignificant. *Id.* at 144-45. He stated that even today, groundwater and surface water monitoring has demonstrated that DEP's ash basins have not caused significant harm to the environment or public health. *Id.* at 388. Witnesses Wells and Williams further testified that these studies culminated in EPA's 1988 Report to Congress, which concluded "that current waste management practices [including unlined ash basins] appear to be adequate for protection of human health and the environment." *Id.* at 162, 223.

Witness Wells testified in detail about the Company's implementation of groundwater monitoring at its Sutton plant in the 1980s and its Weatherspoon plant in the 1990s. *Id.* at 152-58, 162. In addition, he testified that DEP also began monitoring groundwater at Roxboro in conjunction with its construction of an ash landfill. Later in the mid-2000s, DEP voluntarily participated in the USWAG Action Plan, which resulted in monitoring networks being developed at all of its sites. He stated that it was not until 2010 that DEQ required DEP to monitor groundwater at all of its sites. *Id*. at 165. Witness Williams testified that DEP's groundwater monitoring efforts over time reveal a company that was "way ahead" of the industry as a whole. *Id.* at 361.

Regarding seeps, witness Wells asserted that the existence of seeps at ash basins is not evidence that the ash basins were mismanaged. He stated that DEQ was long aware of the existence of seeps but that DEQ exercised regulatory restraint and did not view them as a priority for inclusion of NPDES permits due to the low concentrations of constituents. *Id.* at 186. Witness Wells also faulted witness Lucas for relying on the "new" exceedances since the last rate case, explaining that there were flaws in the Public Staff's analysis. *Id.* at 190-93.

In sum, witnesses Wells and Williams testified that witnesses Lucas, Quarles, and Hart each failed to consider all relevant information, including selectively using information from studies and reports without considering the broader set of available knowledge on the subject, did not give appropriate weight to environmental regulations, and failed to assess in detail industry practices in CCR and other waste management. Further, witness Williams asserted that they also failed to give appropriate weight to the role of DEQ in overseeing DEP's actions. *Id.* at 321-24. Given the Company's forthcoming and cooperative relationship with its regulators, witnesses Wells and Williams concluded that it was unreasonable and unfair for intervenors to cast DEP's CCR management practices in a negative light. *See also id.* at 347-51.

Witness Bonaparte

Witness Bonaparte testified about his observations and findings regarding CCR management strategies and closure planning of CCR surface impoundments in the Southeast region where DEP operates, including the states of Georgia, North Carolina, South Carolina, and Virginia. Tr. vol. 11, 119-20. He summarized:

- Information was reviewed for 93 CCR impoundments at the 40 generating stations. Of these, only three (3.2%) CCR impoundments were identified as having engineered closure plans and/or engineering-related closure planning in the 2009-2011 timeframe, or earlier. A few additional impoundments had received a layer of non-engineered fill above the CCR impoundment or had vegetation growing on the surface of the impoundment.

- Of the 93 CCR impoundments reviewed, 85 (91%) were either directly reported or interpreted as being unlined; most of the CCR impoundments reviewed were reported as being active in the 2009-2011 timeframe; and of the active impoundments the majority were reported as receiving sluiced CCR at the time of the USEPA dam safety assessment reports.

- Only 1 of the 57 CCR Rule closure plans had any indication of closure planning for the subject CCR impoundment for the 2009-2011 timeframe, or earlier.

Id. at 121; DEP Bonaparte Rebuttal Ex. 2 at 9.

Witness Lioy

Witness Lioy challenged AGO witness Hart's methodology from an accounting perspective as flawed and unreliable, including witness Hart's misunderstanding of the "time value of money" concept. *Id.* at 157-64. Witness Lioy also testified that witness Hart failed to consider a number of necessary factors that he would need to determine what DEP would have spent in 1992, 1996, or 2009. *Id.* at 165.

Setting aside witness Hart's misapplication of the time value of money concept, witness Lioy also opined that witness Hart made numerous other errors that render his testimony unreliable. Witness Lioy testified that AGO witness Hart failed to consider a number of factors in his attempt to quantify the amount that DEP would have spent as of the earlier time periods in his analysis (1992, 1996, or 2009) in order to quantify alleged imprudently incurred costs. *Id.* at 165-67. Witness Lioy also concluded that witness Hart's calculations were not prepared in accordance with normal conventions and are unreliable and speculative. *Id.*

Witnesses Doss, Spanos, and Riley

Witness Doss testified that the Company opposes the Public Staff's equitable sharing proposal and witness Maness's recommendations to lengthen the amortization for CCR cost recovery and disallow a return during the amortization period. Witness Doss did not agree with witness Maness's characterization of coal ash ARO related costs as deferred expenses. Tr. vol. 16, 340-41. Witness Doss further disagreed with witness Maness's assertion that the Company can choose whether it will defer coal ash ARO-related costs. *Id.* at 363-65; Tr. vol. 17, 45-46. Lastly, witness Doss disagreed with witness Maness's argument that coal ash ARO costs are not characteristic of assets recorded as used and useful property, arguing instead that the costs incurred (relating to the deferred depreciation and accretion) are used and useful as those costs are reasonable and prudently incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. Tr. vol. 16, 344.

Witness Riley provided testimony on two FASB codified GAAP standards applicable to the Company: ASC 980 and ASC 410. According to witness Riley, ASC 980 addresses requirements specific to regulated entities. In so doing, it provides a linkage between costs and revenues that does not exist for nonregulated companies, and also places a primary emphasis on regulatory ratemaking in the determination of appropriate accounting treatment.

Witness Riley also discussed the requirements of ASC 410, which beginning in 2003 required companies like DEP to assess whether it had a present legal obligation to remove, dispense, or remediate a long-lived capital asset. Tr. vol. 13, 354. Witness Riley noted that receiving less than a full return (which would be at the Company's weighted average cost of capital) would constitute a cost disallowance. *Id.* at 404-06. Witness Riley also provided testimony on the manner in which CCR removal costs are accounted for in depreciation studies. He opined that it was not general industry practice to include those costs in depreciation studies prior to the EPA's adoption of its CCR Rule.

DEP Settlement Testimony

Witness De May

In support of the January 25, 2021 CCR Settlement witness De May testified that the CCR Settlement represents a balanced solution that resolves the coal ash cost recovery debate in North Carolina, providing both immediate and long-term savings for customers and long-term certainty for the Company and its investors and allowing all parties to move forward towards the desired cleaner energy future. He concluded that the CCR Settlement is in the public interest and should be approved.

Witness De May provided an overview of the CCR Settlement. He testified that it resolves among the CCR Settling Parties, subject to Commission approval, CCR cost recovery issues in both DEP's and DEC's current rate cases and the Companies' prior cases in a comprehensive manner for the period beginning January 1, 2015 (when the Company first incurred such costs) through February 28, 2030 — a period of over fifteen years. Witness De May contended that the CCR Settlement requires the Company to reduce the amount of coal ash-related costs to be recovered from customers and grants the Company the ability to earn a return upon the recovered costs at a negotiated cost of equity lower than the Company's allowed ROE. The CCR Settlement also provides customers with immediate and future rate reduction — DEP and DEC together will absorb approximately $1.1 billion (on a North Carolina system basis) through February 2030. Witness De May testified that on a North Carolina retail basis, the net present value of the cost savings to customers (including applicable financing costs) is in excess of $900 million. Importantly, witness De May noted, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic.

Witness De May also summarized the benefits of the CCR Settlement to the Company. He explained that it "validates and affirms the reasonableness and prudence of [each] Company's ash basin closure strategy," provides more certainty and stability regarding cost recovery, and — by preserving the Companies' ability to recover financing costs, albeit at a reduced rate — preserves their access to much needed capital on reasonable terms, also benefitting customers. Finally, the CCR Settlement — in settling the legacy issue — allows the collective focus to shift to the future to cleaner sources of energy, while maintaining the Company's drive to keep electricity affordable and reliable.

Witness De May explained that the CCR Settlement appropriately balances the need for rate relief with the impact of such rate relief on customers. He stated that the Company is pleased that its rates are competitive and below the national average and will remain so under the CCR Settlement, noting that providing safe, reliable, and increasingly clean electricity at competitive rates is key. Witness De May stated that, particularly in light of the current economic conditions faced by customers due to the COVID-19 pandemic, the Company believes the CCR Settlement fairly balances the needs of customers with the Company's need to recover substantial investments made to continue to comply with regulatory requirements and safely provide high quality electric service. And he concluded that given the size of the necessary capital and compliance expenditures the Company faces it is essential that DEP maintain its financial strength and credit quality for the benefit of its customers.

Witness Smith

Witness Smith similarly testified that the Company believes that the CCR Settlement represents a fair, just and reasonable, and balanced solution that provides immediate and long-term savings for customers as well as the long-term certainty the Company and its investors need. Thus, the Company requests that the Commission approve of the CCR Settlement in its entirety. The effect of the CCR Settlement on the Company's requested recovery of CCR costs is shown on Smith CCR Settlement Exhibit 1, page NC-1102CA. As set forth therein, the CCR Settlement provides for DEP to recover $138,134,625 of actual coal ash basin closure and compliance costs plus financing costs of $53,443,112.

Witness Smith testified that, if the Commission approves the CCR Settlement and the First and Second Partial Stipulations with the Public Staff, the Company's revised request for a revenue increase in base rates is reduced to $344 million. She explained that Smith CCR Settlement Agreement Exhibit 2 showed that the Company's revised request for a revenue increase, combined with the Company's request to reduce customer rates by $137 million through its two proposed EDIT riders and the RAL-1 rider, results in a net proposed increase in revenue of $207 million — a $257 million reduction from the amount proposed in the Company's Application. She further noted that these amounts assume the Commission accepts the Company's position on the remaining unsettled revenue issues, mainly depreciation rates. The other nonrevenue issues concern various forward-looking studies and rate designs.

Public Staff Settlement Testimony

Witness Maness

Witness Maness testified that the CCR Settlement would comprehensively resolve the following CCR cost recovery issues: (1) issues pending before the Commission on remand in the 2018 Rate Cases; (2) issues pending before the Commission in the present rate case proceedings; (3) the treatment of CCR costs incurred by DEC from February 1, 2020, through January 31, 2030, and by DEP from March 1, 2020, through February 28, 2030, along with associated financing costs; and (4) how any proceeds received from insurance litigation related to CCR costs would be shared by ratepayers, DEC, and DEP.

In addition, witness Maness explained that from the perspective of the Public Staff, the most important ratepayer benefits of the CCR Settlement are: (1) DEC's and DEP's agreement to forego the combined recovery of CCR costs and associated financing costs in excess of $900 million, on a present value basis, resulting in a significant reduction in the proposed revenue increase in this case; (2) the allocation of the proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR costs and financing costs into 2030. Accordingly, witness Maness stated that the Public Staff believes the CCR Settlement is in the public interest and should be approved.

Witness Boswell

Witness Boswell provided updated schedules showing the impact of the CCR Settlement. She noted that some final adjustments will have to be made after the Commission's issues its order resolving the remaining unsettled issues.

Public Witness Testimony and Consumer Statements of Position

Over the course of the five public witness hearings held in the instant case, during which a total of 58 public witnesses provided testimony to the Commission, many of the witnesses expressed concerns to the Commission regarding the environmental impact of, the handling of, and the costs associated with CCRs.[3] Similarly, many of the written consumer statements of position filed in this proceeding addressed the issues of the environmental impact of, the handling of, and the costs associated with CCRs.

Discussion and Conclusions

The Commission is required to set just and reasonable rates for public utilities. N.C.G.S. § 62-130(a). Just and reasonable rates are those that provide the utility an opportunity to earn a fair return on its property and are fair to the utility's customers. *State ex rel. Utils. Comm'n v. Piedmont Nat. Gas Co.*, 254 N.C. 536, 119 S.E.2d 469 (1961); *State ex rel. Utils. Comm'n v. Duke Power Co*., 285 N.C. 377, 206 S.E.2d 269 (1974). To achieve just and reasonable rates, the utility's revenue must be sufficient to cover the utility's cost of service, plus allow the utility the opportunity to earn a reasonable return on its rate base but must be fair to customers. To this end, the North Carolina Supreme Court has counseled:

> [T]he fixing of "reasonable and just" rates involves a balancing of shareholder and consumer interests. The Commission must therefore set rates which will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right of the utility's intrastate customers to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf.

State ex rel. Utils. Comm'n v. Nantahala Power & Light Co., 313 N.C. 614, 691, 332 S.E.2d 397, 474 (1985), *rev'd on other grounds*, 476 U.S. 953, 90 L.Ed.2d 943 (1986), *appeal after remand*, 324 N.C. 478, 380 S.E.2d 112 (1989) (*Nantahala*).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). However, according to the North Carolina Supreme Court,

> [i]n spite of the fact that North Carolina utilities have the burden of proving that the costs upon which their rates are based are reasonable and prudent,

[3] Raleigh (14/16 witnesses), Wilmington (13/14), Snow Hill (3/5), and Asheville (12/23). No public witnesses appeared at the hearing conducted in Rockingham.

> the reasonableness and prudence of those costs is "presumed" unless the Commission or an intervenor adduces sufficient evidence to cast doubt upon their reasonableness or prudence, at which point the burden to make an affirmative showing of the reasonableness of the costs in question shifts to the utility. *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Bent Creek*). In order to satisfy this burden of production, an intervenor must offer affirmative evidence tending to show that the expenses that the utility seeks to recover "are exorbitant, unnecessary, wasteful, extravagant, or incurred in abuse of discretion or in bad faith or that such expenses exceed either the cost of the same or similar goods or services on the open market or the cost similar utilities pay to their affiliated [utilities] for the same or similar goods or services." *Id.* at 76–77, 286 S.E.2d at 779. If a utility expense is "properly challenged," "[t]he Commission has the *obligation* to test the reasonableness of such expenses." *Id*. at 76, 286 S.E.2d at 779.

State ex rel. Utils. Comm'n v. Stein, 375 N.C. 870, 908, 851 S.E.2d 237, 261-62 (2020) (second and third alterations in original) (*Stein*). The Supreme Court thereafter held that "the record contain[ed] ample evidentiary support for the Commission's determination in the Duke Energy Carolinas proceeding that the intervenors had failed to elicit sufficient evidence to satisfy the burden of production imposed upon them in *Bent Creek*." *Id*. at 911, 851 S.E.2d at 263.

Finally, the Commission's orders must be based on competent, material, and substantial evidence in the record of the instant proceeding. N.C.G.S § 62-65(a). Where settlement has been reached by less than all of the parties in a case, as with the CCR Settlement in this case, that settlement should be accorded full consideration and weighed by the Commission along with all other evidence presented in reaching its decision: "The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." *CUCA I*, 348 N.C. at 466, 500 S.E.2d at 703.

The issues related to the recovery of costs incurred to comply with CAMA and the CCR Rule have been highly contentious in the last several electric utility rate cases. The parties to the proceedings have proffered pages and hours of testimony reviewing the history of coal-fired generation and the handling of coal ash throughout the history of the utilities serving North Carolina consumers, comparing the past coal ash handling practices of these utilities to others across the region and the country, debating what different decisions perhaps should have been made and when, and attempting to quantify the impact of such decisions on the CCR costs now sought to be recovered from customers. Additionally, the Commission has received significant testimony from public witnesses on these issues. Indeed, coal ash — including environmental impact and associated cost — was the predominant topic at the public witness hearings held in the instant case.

As noted above, the Public Staff has argued that responsibility for these costs (not otherwise imprudently incurred) should be shared equally between the utility and its customers. Other parties have argued that the utility should bear all or substantially all of the costs of compliance with the recently adopted state and federal requirements. After careful consideration, the Commission determined in the 2018 Rate Cases that the costs incurred, with one exception, were reasonable and prudent but imposed a management penalty in each case, which ultimately reduced the return that each Company would recover during the five-year amortization period.

Upon appeal of the Commission's 2018 Rate Case orders on this issue, the North Carolina Supreme Court remanded the cases to the Commission for further proceedings to consider the Public Staff's equitable sharing proposal. In summary, the Court concluded

> that the Commission did not err by: (1) allowing the inclusion of a large majority of the utilities' coal ash costs in the cost of service used for the purpose of establishing the utilities' North Carolina retail rates; (2) interpreting N.C.G.S. § 62-133(d) to authorize the Commission, in the exercise of its discretion, to allow a return on the unamortized balance of the deferred operating expenses . . . . On the other hand, we hold that the Commission erred by rejecting the Public Staff's equitable sharing proposal without properly considering and making findings and conclusions concerning "all other material facts" as required by N.C.G.S. § 62-133(d). As a result, we affirm the Commission's decisions, in part, and reverse and remand the Commissions' decisions for further proceedings not inconsistent with this decision, in part.

Stein, 375 N.C. at 946-47, 851 S.E.2d at 286.

The Court's opinion was issued on December 11, 2020 — after the close of the evidentiary record in the instant case. Subsequent to the issuance of the opinion, the CCR Settling Parties — each of which had offered evidence on the issue of CCR cost recovery in the rate cases and had participated in the appeals of the Commission's 2018 Rate Case orders — worked to reach a compromise on the issues. The CCR Settlement seeks to resolve not only the current DEP rate case but the current DEC rate case, the 2018 Rate Cases that have been remanded back to the Commission, and future costs to be incurred through January 2030 for DEC and February 2030 for DEP.

On February 12, 2021, upon joint motion of the CCR Settling Parties, the Commission issued an order reopening the evidentiary records, allowing testimony or comments on the CCR Settlement, and allowing requests for hearing by any party. The order made clear that a party's choice not to file a request for a hearing would be deemed by the Commission as a waiver by that party of its right to cross-examine the witnesses who provided testimony regarding the CCR Settlement. No testimony or comments were filed by any party, and no party requested a hearing. Thus, all parties waived their rights to introduce additional testimony or to cross-examine DEP's or the Public Staff's witnesses on their settlement testimony. The Commission will accept the CCR Settlement and the subsequently filed testimony in support of the CCR Settlement into the record of evidence in this case.

The Commission recognizes that the CCR Settlement is the product of give-and-take between the CCR Settling Parties — DEP, DEC, the Public Staff, the AGO, and the Sierra Club. The settlement and supporting testimony by the parties offer an immediate and longer-term resolution of the ratemaking treatment of CCR costs in lieu of the positions previously advocated by the parties. The settlement aims to resolve contentious issues in this and other DEP and DEC rate cases, including the 2018 Rate Cases, and strikes a balance between the Companies and their customers that all of the CCR Settling Parties found to be appropriate. The Company explains that the CCR Settlement provides benefit to customers through both immediate and future rate reduction — DEP and DEC together will absorb approximately $1.1 billion (on a North Carolina system basis) in CCR-related costs over the time period covered by the CCR Settlement, reducing the amounts they would otherwise seek to recover from customers. On a North Carolina retail basis, the net present value of the savings to customers from forgone CCR cost recovery (including applicable financing costs) amounts to more than $900 million. Importantly, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic. De May Settlement Testimony at 4:11-20. The Commission takes note that the Public Staff generally supports this position, asserting that the settlement obligates DEP and DEC to forego recovery of costs in excess of $900 million (combined DEP and DEC), resulting in a significant reduction in the proposed revenue increase in this case. Maness Settlement Testimony at 5:14-19.

The Commission recognizes that for purposes of this proceeding DEP agrees in the CCR Settlement to reduce the balance of deferred CCR costs to be recovered in this rate case by $261 million. DEP will cease to accrue financing costs on this amount as of December 31, 2020, resulting in additional savings to customers. Additionally, the CCR Settlement provides that DEP will recover the remaining balance of its deferred costs over a five-year amortization period, plus reduced financing costs during the amortization period calculated based on (1) DEP's cost of debt set forth in the Second Partial Stipulation, adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.60% ROE set forth in the Second Partial Stipulation, and (3) a capital structure of 48% debt and 52% equity set forth in the Second Partial Stipulation.

For purposes of future rate case proceedings, DEP has agreed to reduce the balance of CCR costs to be recovered by $162 million and agrees that this amount shall cease to accrue financing costs as of December 31, 2020, which provides additional savings to customers. DEP has agreed to recover financing costs during the amortization period established in future proceedings at a reduced rate.

Finally, the Commission notes that the CCR Settling Parties have agreed to waive their rights to challenge future CCR costs on the basis that the Company's historical coal ash management practices were inadequate and led to unreasonable CCR costs being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. The CCR Settling Parties reserve their rights only to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

Thus, the CCR Settling Parties in the CCR Settlement settle the ratemaking treatment of CCR costs in this rate case and future rate cases. The settlement aims to reduce costs that are passed on to customers, to avoid additional protracted litigation over the Companies' historical management practices, and to provide some closure to the debate that has been waged for many years. Indeed, the parties to the Companies' rate cases have extensively litigated these contested issues since at least the filing of the 2018 Rate Cases, and the CCR Settlement seeks to resolve comprehensively certain issues for CCR Costs incurred by DEP from January 1, 2015, through February 28, 2030.

While the CCR Settlement is a nonunanimous settlement, the Commission places significant weight on the fact that the Public Staff and the AGO, each of which has litigated the issues associated with CCR cost recovery vigorously in these cases and advocated zealously for consumers, are parties to the CCR Settlement. Moreover, beginning with the 2018 Rate Cases, the CCR Settling Parties have advocated for significantly different ratemaking treatment for CCR costs, particularly as to how much cost should be borne by customers versus by the Companies. Thus, the Commission recognizes the extent of the compromise and give and take that was necessary to achieve consensus on the ratemaking issues. As noted by Public Staff witness Maness, "among the most important benefits provided by the CCR Settlement are: (1) the agreement of DEC and DEP to forego recovery of CCR Costs and associated Financing Costs in excess of $900 million (combined DEC and DEP), on a present value basis, over the period from January 1, 2015, through January 31, 2030 (DEC), and February 28, 2030 (DEP), resulting in a significant reduction in the proposed revenue increase in this case; (2) the agreement to allocate any proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR and Financing Costs into 2030 among the parties to the CCR Settlement and possibly the appellate courts." Maness Settlement Testimony at 5:10-6:3. For these reasons, the Public Staff concludes that the CCR Settlement is in the public interest. Similarly, as noted by Company witness De May, the settlement "represents a balanced solution" that provides both immediate and long-term savings for customers while providing the certainty the Company requires to meet its business needs. Further, witness De May explains that the settlement allows the Company and the CCR Settling Parties to put the debate behind them and move forward to focus on a cleaner energy future. De May Settlement Testimony at 3:8-16. For these reasons, the Company concludes that the CCR Settlement is in the public interest.

CUCA is the one party to the proceeding that presented evidence regarding DEP's CCR costs but did not join the CCR Agreement.[4] CUCA witness O'Donnell testified that the North Carolina legislature passed CAMA in 2014 in response to the Dan River spill and that CAMA is more stringent than the CCR Rule. He recommended that DEP not be allowed to recover CCR costs associated with any plant that is not subject to the CCR Rule but that is subject to CAMA. He further recommended that to the extent any site is no longer receiving coal ash, remediation costs should not be paid for by ratepayers in this case or any future cases. CUCA's position was refuted by the Company in this case. In addition, CUCA's position was previously rejected by the Commission in DEC's 2018 Rate Case. It was similarly raised by CUCA, refuted by the Company, and rejected by the Commission in the DEP's 2018 Rate Case. These Commission determinations were upheld by the North Carolina Supreme Court in *Stein*. As was the case in the 2018 proceeding, CUCA witness O'Donnell did not quantify any amount that should not be recovered based on the contention that CAMA was enacted in response to the Dan River spill or that CAMA has resulted in the Company's incurring identifiable incremental costs. Rather, he testified simply that consumers should not pay for all of the Company's costs incurred and that the costs should be split equally among the Company and its customers, similar to the recommendation of the Public Staff. However, the Commission notes that the Commission's adoption of the CCR Settlement provides CUCA with its requested relief of a sharing of CCR costs.

In its Order Declining to Adopt Proposed Settlement Rules, the Commission emphasized that "settlements should be encouraged, and that the Commission should do all it lawfully and reasonably can to facilitate the parties' efforts to reach a full and fair settlement." *Rulemaking Proceeding to Consider Proposed Rule Establishing Procedures for Settlements and Stipulated Agreements*, No. M-100, Sub 145, at 10 (N.C.U.C. Mar. 1, 2017). In the instant proceeding, after years of litigation before this body and the courts, the CCR Settling Parties have worked to achieve a settlement of their views and what they perceive to be a full and fair resolution of their disparate positions. In recognition of the foregoing, and in light of the evidence in the record, the Commission is persuaded that the compromise embodied in the CCR Settlement is in the public interest. The CCR Settlement appropriately resolves the issues involving the ratemaking treatment of the costs incurred in connection with DEP's management, handling, and remediation of CCRs, including the financing costs incurred while those costs are deferred and while they are being recovered. In addition, the CCR Settlement provides benefits to customers, including a significant reduction in the amount of costs to be recovered by the Company, certainty as to the application of insurance proceeds for customers' benefit, and the avoidance of protracted and expensive litigation regarding the Companies' historical handling of CCRs. The CCR Settlement, which provides significant savings to customers in the near term, also appropriately balances the need for rate relief with the impact of such rate relief on customers in light of the current economic conditions faced by customers due to the COVID-19 pandemic.

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[4] The Commission notes that CUCA is indicated as "not objecting" to the CCR Settlement and did not request an opportunity to present additional evidence on the CCR Settlement or cross-examine the witnesses of the Company or the Public Staff on the CCR Settlement.

At the four public witness hearings conducted by the Commission in this proceeding in which public witnesses appeared and testified before the Commission, a majority of those witnesses who testified expressed concerns regarding the costs and impacts of coal-fired electricity generation. At those hearings, the Commissioners heard first-hand the many perspectives and opinions of customers as to the clean-up of coal ash and the associated costs. Specifically, the following witnesses provided testimony expressing that customers should not bear responsibility for paying for the clean-up of CCRs: (1) in Raleigh 14 out of the 16 public witnesses, including Adamsky, Hutchby, Springer, Seelam, Thompson, Huang, Reibold, Duvall, Black, Moriarty, Cain, Owens, Guckert, and Weston; (2) in Wilmington 13 out of the 14 public witnesses, including Harton, Vlasits, Reber, Willis, Buckles, Sordellini, Endo, Holder, Dicks-Maxwell, Wright, and Peterson ; (3) in Snow Hill three out of the five public witnesses, including Jones, Herring, and Lanier; and (4) in Asheville 12 out of the 23 public witnesses, including Scales, Biziewski, Strawderman, Holt, Jones, Saulsbury, Mandler, Moore, Mattox, Brame, Noyes, and Resnick. Tr. vol. 2, 19-30, 32-37, 45-68; tr. vol. 3, 19-24, 36-48, 56-68; tr. vol. 4, 15-18, 32-36; tr. vol. 5, 23-25, 27-31, 40-43, 51-55, 61-70, 74-78. In addition, those who wrote to express concern emphasized many of the same perspectives. Of the numerous statements of consumer position filed in the docket a majority expressed that customers should not bear responsibility for costs associated with the clean-up of coal ash. *See generally*, Docket No. E-2, Sub 1219CS. Thus, based on the perspectives and concerns consistently expressed by witnesses at the public hearings and in the statements of consumer position filed in the docket, the Commission concludes that the history and legacy of coal-fired electricity generation by the Company is an issue of significant importance to its customers, and their perspectives must be given weight in the Commission's decision-making process. While the CCR Settlement may not go as far as many customers advocated, it strikes a fair balance for customers that the Commission determines will reduce costs (and rates) associated with CCRs, particularly in the near term, and furthers the Company's financial health and access to capital at a reasonable cost.

For these reasons, the Commission concludes that the CCR Settlement is in the public interest and should be approved. Moreover, the Commission concludes that the ratemaking treatment of CCR costs, set forth in the CCR Settlement, in conjunction with the other decisions contained within this Order, results in just and reasonable rates for DEP's customers.

Finally, the Commission asked a number of questions at the hearing in this case, including requests for late-filed exhibits analyzing the issue, regarding the possibility to recovering future CCR costs contemporaneously with the expense as an alternative to deferral and amortization, as proposed by the Company in its previous rate case. The Commission notes that the CCR Settlement does not involve such a cost recovery mechanism, opting instead to follow the "spend-defer-recover" method. In accepting and adopting the CCR Settlement, the Commission is not deciding that a cost recovery mechanism that would allow the Company to recover contemporaneously as costs are incurred is without merit. Rather, given the greater certainty that exists with respect to annual costs to be incurred, the Commission sees merit in such an approach, particularly if structured to result in savings to customers. The Commission directs the Company to consider the proper extent to which a contemporaneous cost recovery mechanism could be joined with the “spend-defer-recover” method prior to the next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-26

ARO Accounting

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

There has been substantial discussion devoted to the subject of “ARO accounting” in the current proceeding as well as prior DEP proceedings. The Commission will not discuss in detail here the testimony presented by the various parties but will summarize the pertinent facts.

In June 2001 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards 143, Accounting for Asset Retirement Obligations (SFAS 143), which addressed financial accounting and reporting requirements associated with an entity’s legal requirement to retire a long-lived asset. Specifically, SFAS 143 required an entity to recognize the fair value of a liability for an asset retirement obligation (ARO), in the period in which it is incurred if a reasonable estimate of the fair value can be determined. Additionally, upon initial recognition of a liability for an ARO, an entity was required to capitalize an asset retirement cost (ARC) by increasing the carrying amount of the related long-lived asset by the same amount as the liability. SFAS 143 was later codified as Accounting Standards Codification 410, Asset Retirement and Environmental Obligations (ASC 410).

In response to the issuance of SFAS 143, on October 30, 2002, the FERC issued a Notice of Proposed Rulemaking to revise the USOA so that FERC accounting requirements would be consistent with those used by FERC regulated entities for financial reporting purposes. On April 9, 2003, the FERC issued an order amending the USOA. *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Order No. 631, 103 FERC ¶ 61,021, *reh’g denied*, Order No. 631-A, 104 FERC ¶ 61,183 (2003). Specifically, FERC added new balance sheet and income statement accounts. The FERC ruled that no FERC-regulated entity with formula rate tariffs could include ARO costs in their billing determinations without prior approval. As a FERC-regulated entity DEP must comply with the USOA. In addition, Commission Rule R8-27 states that the Commission adopted the FERC USOA as the accounting rules applicable to electric utilities under its jurisdiction subject to certain exceptions and conditions. One such exception is that electric utilities under the jurisdiction of this Commission are required to seek approval to record any items in FERC account 182.3 - Other Regulatory Assets.

On December 23, 2002, in response to FASB's issuance of SFAS 143, DEP filed a petition in Docket No. E-2, Sub 826 for authority to place certain ARO costs in a deferred account. A request for deferral accounting was necessary so that adoption of SFAS 143 "would have no impact on [DEP's] operating results or return on rate base for North Carolina retail regulatory purposes" such that DEP's "North Carolina retail rate base, net operating income, and regulatory return on common equity" would be the same as they would have been absent the implementation of SFAS 143. Order Granting Motion for Reconsideration and Allowing Deferral of Costs, *Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account*, No. E-2, Sub 826, at 11-12 (N.C.U.C. Aug. 12, 2003) (Sub 826 Order).

In its Sub 826 Order the Commission required DEP to make a filing setting forth the journal entries it recorded when initially implementing SFAS 143. Further, DEP was required to file annual reports reconciling the account balances in the Company's annual report filed pursuant to Commission Rule R1-32 and the annual North Carolina retail cost of service studies filed with the Commission.

On January 20, 2004, DEP filed the required journal entries. As shown therein, at the time of implementation of SFAS 143 the only ARO recorded by DEP was for decommissioning of its nuclear plants. A review of subsequent reconciliation reports shows that it was not until DEP filed its reconciliation report for 2014, after the enactment of CAMA, that there was an ARO associated with coal ash removal. After the enactment of the CCR Rule, the report for 2015 showed a significant increase in the ARO coal ash removal.

DEP's Chief Financial Officer, Brian Savoy, wrote a letter to the Commission dated December 21, 2015 (Savoy letter), explaining that due to both CAMA and the CCR Rule, the ARO recorded on DEP's books as of November 30, 2015, was approximately $2.13 billion but noted that actual costs to comply with CAMA and the CCR Rule could be materially different. The Company stated that it was not seeking further specific accounting approval at that time but was simply providing an explanation of its accounting for ash basin closure and compliance costs for the Commission's information. DEP stated that only actual costs resulting in cash outlays by the Company related to ash basin closure, plus carrying charges, would result in amounts for which the Company would seek accounting and rate treatment in future filings. In the current proceeding, DEP witness Riley explained this concept when he testified that ARO assets and liabilities are presented on a company's balance sheet as a result of accounting journal entries, not from investor or customer contributions, and therefore are not considered for ratemaking purposes until actual costs are expended. Tr. vol. 23, 131.

DEP made such a petition for an accounting order on December 30, 2016, in Docket No. E-2, Sub 1103. In that filing DEP requested approval to defer, in a regulatory asset, costs incurred after January 1, 2015, to comply with federal and state regulations and a return on those costs at the Company's approved weighted cost of capital, until the approval of new rates in the Company's next base rate case. DEP stated that from January 2015 through November 2016, the Company had incurred $291.9 million of expenses for state and federal compliance. On July 10, 2017, the Commission issued an Order consolidating DEP's request with its then pending general rate case proceeding, Sub 1142.

Prior to seeking rate recovery, the Company's requests and the Commission's decisions were simply intended to ensure that DEP complied with GAAP and FERC accounting requirements but also that such compliance did not impact North Carolina retail ratemaking. When DEP requested recovery in rates of deferred ash basin closure costs the issue before the Commission was no longer one of accounting but rather of ratemaking.

The approval by the Commission of a five-year amortization period for deferred costs in Sub 1142 did not change the Company's requirement to comply with GAAP and FERC. The Company must still record AROs and ARCs; however, for financial reporting purposes those amounts will be adjusted for amounts approved for recovery in rates. This is shown on DEP Late Filed Exhibit No. 24 where the amount recorded in Account 182.3 Regulatory Assets "theory" will be transferred to Account 182.3 Regulatory Assets "spend". The same accounting was set forth in Public Staff Late Filed Exhibit No. 4.

The Commission reiterates that it will not discuss in detail the various testimony surrounding ARO accounting, ARO-related accounting, deferred expenses, or capitalized costs. The nomenclature applied to the costs which DEP has incurred and will continue to incur in order to comply with both CAMA and the CCR Rule is not pertinent to the ratemaking treatment of such costs. The Commission determined in Finding of Fact No. 50 in the Sub 1142 Order that the Company's request to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements was reasonable and appropriate. The Commission also determined in Finding of Fact No. 51 that DEP expects to incur substantial costs related to coal ash remediation in future years, and that it was just and reasonable to allow deferral of those costs, with a return at the net-of-tax overall cost of capital approved in the 2018 DEP Rate Order, and that the ratemaking treatment of those costs would be addressed in future rate proceedings. The instant proceeding is such a proceeding. The only determination required of the Commission in this proceeding is the prudence of the Company's expenditures and the appropriate amortization period for recovery of such prudently incurred costs. These questions are addressed elsewhere in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27-32

Capital Structure, Cost of Capital, and Overall Rate of Return

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations entered into between DEP and several parties; the testimony and exhibits of DEP witnesses D'Ascendis, Newlin, Young, and Fetter, Public Staff witnesses Woolridge and Hinton, AGO witness Baudino, Commercial Group witness

Chriss, CIGFUR witness Phillips, and CUCA witness O'Donnell; and the entire record in this proceeding.

A. Rate of Return on Equity Capital

Summary of the Evidence

In his direct testimony witness D'Ascendis recommended an ROE of 10.50%; however, in its Application, as a rate mitigation measure, the Company requested approval for its rates to be set using an ROE of 10.30% and an overall rate of return of 7.41%. The Company later stipulated to an ROE of 9.75% in individual settlement agreements with Harris Teeter, the Commercial Group, CIGFUR, Vote Solar, NCSEA and NCJC et al., which is a decrease from the 9.90% ROE and overall rate of return of 7.09% authorized by the Commission in the Company's last rate case, Sub 1142. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation that provides for an ROE of 9.60%. As a result, the HT Stipulation, CG Stipulation, CIGFUR Stipulation, Vote Solar Stipulation, and NCSEA/NCJC et al. Stipulation were each amended as previously described to provide that if the Commission enters a final order in this docket approving a rate of return of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

Witnesses for the Public Staff, CIGFUR, the AGO, the Commercial Group, and CUCA also filed direct testimony on the appropriate ROE to be established in this rate case. This evidence was followed by the Public Staff First and Second Partial Stipulations and the other intervenor settlements, supplemental testimony of witness Baudino, rebuttal, supplemental rebuttal, and settlement testimony of witness D'Ascendis, settlement testimony of witness Woolridge, and finally testimony of witnesses D'Ascendis, Baudino, and O'Donnell at the consolidated hearing in this matter. In addition to this expert testimony the Commission received the testimony of a number of public witnesses on DEP's proposed rate increase as well as numerous statements of consumer position. All of this evidence is summarized below.

DEP Direct Testimony

Company witness D'Ascendis recommended in his direct testimony an ROE of 10.50%, which was the midpoint of his recommended range of 10.00% to 11.00%. Tr. vol. 11, 250. Witness D'Ascendis stated that the ROE, or the cost of equity, is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return represents the cost of equity capital. Witness D'Ascendis testified that the cost of equity is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. Since the cost of equity cannot be directly observed, it must be estimated or inferred based on market data and various financial models. Witness D'Ascendis testified that each of those models is subject to specific assumptions, which may be more or less applicable under differing market conditions. *Id*. at 260-61.

Witness D'Ascendis noted that, as all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. *Id*. at 251. He therefore relied on three widely accepted approaches to develop his ROE determination: (1) the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model; (2) the Capital Asset Pricing Model (CAPM); and (3) the Bond Yield Plus Risk Premium approach. *Id*. He noted, however, weaknesses in the Constant Growth DCF Model, namely that those results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions and therefore discounted those results. *Id*. at 252. The Constant Growth DCF Model produced ROE results ranging from a low of 8.78% to a high of 9.85% and the Risk Premium-based approaches, including the CAPM, Empirical CAPM, and Bond Yield Plus Risk Premium methods, produced results ranging from a low of 8.44% to a high of 10.93% in connection with one variant of the Empirical CAPM. *Id*. at 258. Finally, the Expected Earnings analysis, which is used to assess the reasonableness of the DCF, CAPM, and Bond-Yield Plus Risk Premium results, produces an ROE estimate with a mean of 10.47% and a median of 10.54%. *Id*. at 259. Witness D'Ascendis noted that FERC uses the Expected Earnings analysis to determine the "zone of reasonableness." *Id*. at 272.

Witness D'Ascendis provided extensive testimony concerning the capital market environment and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness D'Ascendis also focused upon capital market conditions as they affect the Company's customers in North Carolina. *Id*. at 299-309. Specifically, his analysis found that the North Carolina and national economies continue to be highly correlated with one another. *Id*. at 300-01. He concluded therefore that North Carolina conditions "continue to be reflected in the models and data used to estimate the Cost of Equity." *Id*. at 301.

In addition to his econometric models and evaluation of capital market risks, witness D'Ascendis also considered Company-specific business risks in arriving at his final ROE recommendation. These included (1) the risks associated with certain aspects of the Company's generation portfolio, and (2) the Company's significant capital expenditure plan. *Id*. at 283-84.

Regarding economic conditions in North Carolina, witness D'Ascendis noted that North Carolina and the counties comprising DEP's service area "continue to steadily emerge from the economic downturn that prevailed during 2009-2010 and have experienced significant economic improvement during the last several years." *Id*. at 308.

Public Staff Testimony

Witness Woolridge performed DCF and CAPM analyses for both his and witness D'Ascendis' proxy groups of electric utilities. Tr. vol. 15, 528-29. Witness Woolridge developed his DCF growth rate after reviewing growth rate measures including historic and projected growth rate measures and evaluating growth in dividends, book value, earnings per share (EPS), and growth rate forecasts from Yahoo, Reuters, and Zack's. *Id*. at 589-90. Witness Woolridge applied the DCF model and CAPM that yielded the following results:

Discounted Cash Flow (DCF) – Electric Proxy Group
- 8.15% Equity Cost Rate

DCF – D'Ascendis Proxy Group
- 8.40% Equity Cost rate

CAPM – Electric Proxy Group and D'Ascendis Proxy Group
- 6.70% Equity Cost Rate

Id. at 616.

In witness Woolridge's CAPM analysis he used for the risk-free interest rate the top end of the range of yields on 30-year U.S. Treasury bonds over the 2013-2020 time period, 3.50%. *Id*. at 602. He used the Value Line Investment Survey betas of 0.55 for both his and witness D'Ascendis' proxy groups. *Id*. at 604. Witness Woolridge's market risk premium was 5.75%, which gave the most weight to the market premium estimates of KPMG, CFO Survey, Duff & Phelps, the Fernandez survey, and Damodaran. *Id*. at 614-15. He testified that his 5.75% value is a conservatively high estimate of the market risk premium. *Id*. at 615.

Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness D'Ascendis' proxy groups is in the 6.70% to 8.40% range. *Id*. at 616. However, witness Woolridge took into account the fact that his range was below the authorized ROEs for electric utilities nationally and made a primary recommendation of a 9.00% ROE, assuming a 50% common equity ratio. *Id*. at 617. Witness Woolridge also provided an alternative recommendation of an 8.40% ROE based on the Company's originally requested capital structure of 53% equity and 47% debt. *Id*.

Witness Woolridge did not perform an ECAPM analysis. He testified that the ECAPM is an ad hoc version of the CAPM. *Id*. at 653.

Witness Woolridge also testified as to current capital market conditions as of the date of his testimony in April 2020. He stated that although the Federal Reserve increased the Federal Funds rate between 2015 and 2018, interest rates and capital costs remain at low levels. *Id*. at 538, 542. Witness Woolridge also pointed out that in 2019 interest rates fell dramatically with moderate economic growth and low inflation, while the Federal

Reserve cut the federal fund rate in July, September, and October and the 30-year yield traded at all-time low levels. *Id*. at 540. He noted that from January 1, 2020, through March 18, 2020, the yield on the benchmark 30-year Treasury bond had declined from 2.0% to 1.6%, even trading as low as 0.9%, an all-time low. *Id*. at 672-73. He found that the volatility in the markets since mid-February suggested a state of disequilibrium such that analyses using current market data would not provide reliable estimates of the cost of equity capital. Instead, he relied on data from the first week of February 2020. *Id*. at 685.

Witness Woolridge responded to witness D'Ascendis' assessment of the economic conditions in North Carolina prior to the COVID-19 pandemic. He generally agreed with witness D'Ascendis' general conclusion that economic conditions in North Carolina had improved since the Company's last rate case. Witness Woolridge stated that "[a]s highlighted by the correlations between U.S. and North Carolina economic data . . . economic conditions have improved with the overall economy over the past decade." Tr. vol. 15, 667. He argued, however, that although economic conditions generally had improved in North Carolina, other conditions such as a higher unemployment rate in the DEP service territory than the national average, a median household income in North Carolina that is lower than the national figure and the greater than 100 basis point difference in DEP's requested ROE and the average authorized ROEs for electric utilities in 2018-2019, do not support the Company's proposed ROE. *Id*. at 667-68.

AGO Testimony

Witness Baudino proposed an ROE of 9.00% based on a capital structure comprising 51.50% equity and 48.50% long-term debt. Witness Baudino's recommendation was based upon his DCF-based market approaches along with the CAPM approach. Tr. vol. 13, 444-45. Witness Baudino later provided prefiled Supplemental Direct Testimony where he updated interest rates and market data "since the beginning of March 2020 when concerns about the COVID-19 pandemic began to roil financial markets with extreme volatility." *Id*. at 511. Witness Baudino testified regarding the recent volatility in the markets, including "sharp increase in betas for the companies in the proxy group." *Id*. at 520. His analysis resulted in an updated DCF ranging from 8.29 to 9.28, an increase from his initial DCF range of 8.21 to 9.02. *Id*. at 518; tr. vol. 2, 128. Likewise, witness Baudino testified that nationally the real GDP "declined in the first quarter of 2020 by -5.0%, according to the Bureau of Economic Analysis." Tr. vol. 13, 523. Nevertheless, he continued to recommend a 9.00% ROE in his supplemental direct testimony. *Id*.

Witness Baudino further testified that his 9.00% ROE recommendation was "reasonably close to recently allowed ROEs." Tr. vol. 13, 480. As a reference point to determine "reasonably close" he relied upon average public utility commission allowed ROEs during 2016, 2017, 2018, and 2019, *see* Tr. vol. 2, 135-37, which he calculated as 9.60%, 9.68%, 9.56%, and 9.57%, respectively. Tr. vol. 13, 478-79.

CUCA Testimony

Witness O'Donnell proposed an ROE of 8.75%, primarily based upon DCF modeling and CAPM methodologies, as well utilizing a comparable earnings approach. Tr. vol. 14, 229. Witness O'Donnell's DCF analysis results ranged from 7.0% to 10.0% with a midpoint of 8.50%, his CAPM analysis ranged from 5.0% to 7.0% with a midpoint of 6.50%, and his comparable earnings analysis ranged from 9.25% to 10.25% with a midpoint of 9.75%. *Id*. He believed that the midpoint of his DCF was the most accurate representation of market conditions as supported by his CAPM analysis but chose a return in the upper end of his DCF range based on allowed returns from other jurisdictions. *Id*.

Commercial Group Testimony

Although he did not provide an ROE analysis in his testimony, witness Chriss testified that the Company's proposed ROE was significantly higher than rates previously approved by the Commission from 2016 to present. Tr. vol. 14, 86-87. Likewise, witness Chriss indicated that the Company's proposed ROE is significantly higher than most reported ROE decisions by utilities commissions from 2016 to the present. *Id*. at 87-88. He testified that according to S&P Global Market Intelligence, 154 decisions were rendered over that time frame, with results ranging from 8.40% to 11.95%, and the median authorized ROE was 9.60%. *Id*. at 87. Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average ROE for vertically integrated utilities authorized from 2016 through the time of his direct testimony filing was 9.74%, and the trend in these averages has been relatively stable. *Id*. at 87-88. As previously noted, the Commercial Group subsequently entered into a settlement agreement where the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, the parties agree that the provisions of their agreement on ROE and capital structure shall have been fulfilled.

CIGFUR Testimony

CIGFUR witness testified that DEP's requested ROE of 10.30% is unreasonable and should be rejected. Tr. vol. 16, 316-17. He presented evidence that the national average authorized ROE for vertically integrated electric utilities is currently 9.73%. *Id*. at 317. He recommended that a reasonable ROE for DEP should not exceed the current national average for vertically integrated electric utilities. *Id*. Similar to the Commercial Group, CIGFUR subsequently entered into a settlement agreement where the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, CIGFUR would agree that the provisions of its agreement on ROE and capital structure shall have been fulfilled.

DEP Rebuttal Testimony

Witness D'Ascendis responded to and discussed in detail the intervenor witnesses' criticisms of his ROE conclusions and recommendations. He indicated that "none of their arguments caused me to revise my conclusions or recommendations." Tr. vol. 1, 46. Witness D'Ascendis stated that "financial models are important tools in determining returns and understand[s] that because all [models] are subject to assumptions, no one method is most reliable at all times, or under all conditions" and therefore it "remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results." Tr. vol. 11, 355.

Generally, witness D'Ascendis advised that over the last five years nearly all authorized ROEs for vertically integrated electric utilities have been above the intervenor witnesses' recommendations. *Id*. at 353. Witness D'Ascendis also included as Chart 1 of his Rebuttal Testimony a comparison of authorized ROEs for other vertically integrated utilities from 2015 through January 2020 that he testified shows that the intervenor witness recommendations[5] are far below the ROEs available to other such utilities. *Id.* at 354.

Witness D'Ascendis indicated that the "significant departure" represented by the recommendations of witnesses Baudino and O'Donnell raises two concerns. First, DEP must compete with other companies, including utilities, for the long-term capital needed to provide safe and reliable utility service, and such competition means that the Company would be at a disadvantage in the capital markets if the Commission were to approve an ROE in the ranges recommended by witnesses Baudino and O'Donnell. As a result, he testified a likely outcome would be increasing reluctance on the part of investors to provide capital at reasonable costs and terms. Witness D'Ascendis also noted that while they are not exclusively relied upon, authorized ROEs provide observable and measurable benchmarks against which return recommendations may be assessed. *Id*. at 354-55.

Witness D'Ascendis criticized the growth rates witness Baudino applied to the Constant Growth DCF model and his reliance on the Constant Growth DCF model to determine the Company's ROE, the Market Risk Premium witness Baudino used in the CAPM, witness Baudino's statements concerning the relevance of the ECAPM analysis, as well as the reasonableness of his Bond Yield Plus Risk Premium analysis, among other factors. *Id*. at 487. He responded to each and concluded that none of witness Baudino's arguments resulted in the revision of witness D'Ascendis' conclusions or recommendations.

Witness D'Ascendis also challenged witness O'Donnell's application of the Constant Growth DCF and subsequent recommendation for an ROE of 8.75%. *Id*. at 529. Witness D'Ascendis explained that the reliance on historical growth rates by witnesses O'Donnell and Baudino as part of their Constant Growth DCF modeling does not adequately encapsulate how the model is a forward-looking measure of investors' expectations and there is support that future growth is superior to that of historically oriented growth measures. In response to Witness O'Donnell's contention that the DCF

[5] The chart prepared by witness D'Ascendis reflects witness Woolridge's original 9.00% ROE recommendation.

approach is far superior to all the models now used by practitioners, witness D'Ascendis contended that no support was offered for that assertion. In response to witness O'Donnell's use of the Retention Growth Model, witness D'Ascendis tested the relationship between retention ratios and future growth rates and demonstrated that earnings growth actually *decreased* as the retention ratio increased. Tr. vol. 11, 540. Witness D'Ascendis testified that the CAPM addresses comparable risk in a way that the DCF-based methods do not; the Beta coefficient reflects "systematic" risk, which provides a direct measure of relative risk. *Id*. at 549.

Additionally, witness D'Ascendis testified that the intervenor witnesses fail to recognize the risks faced by the Company and their recommended ROEs do not appropriately reflect the capital market environment. *Id*. at 351. To illustrate his point that an ROE in the range recommended by Baudino and O'Donnell would risk devaluing the Company's equity and, thus, its ability to compete for capital, witness D'Ascendis provided an example of a recent rate decision for CenterPoint Energy Houston Electric in which the financial community responded negatively to an adverse regulatory outcome. *Id*. at 527.

Witness D'Ascendis also prefiled supplemental rebuttal testimony to update his ROE models and respond to the prefiled supplemental direct testimony of AGO witness Baudino regarding current and expected capital markets and their effect on the cost of equity.

Witness D'Ascendis noted that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the ROE. Tr. vol. 11, 614. In addition, evidence was presented that shows that the current level of volatility, which is 50% higher than normal levels, is expected to persist until at least the end of 2021. *Id*. at 612.

Witness D'Ascendis updated his ROE analyses based on market data as of June 30, 2020, resulting in a DCF ranging from 7.76% to 9.67%, a CAPM ranging from 10.19% to 15.70%, an ECAPM ranging from 10.94% to 15.70%, a Bond Yield Risk Premium ranging from 9.96% to 10.25%, and an Expected Earnings ranging from 5.50% to 13.56%. *Id*. at 594-95; D'Ascendis Supplemental Rebuttal Exs.1-6.

Stipulations

As discussed above, in separate stipulations with CIGFUR, the Commercial Group, and Harris Teeter, the Company stipulated to an ROE of 9.75%. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation which among other things provided for an ROE of 9.60%. Thereafter, the other intervenor settlements were amended to provide that if the Commission enters a final order in this docket approving a rate of return of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

DEP Settlement Testimony

Witness D'Ascendis provided testimony supporting the Second Partial Stipulation reached between the Public Staff and the Company, explaining that though the stipulated ROE of 9.60% is somewhat below his recommended range, he recognized that the settlement represents negotiation between the parties of otherwise contested issues and that the Company believes that the Second Partial Stipulation's ROE and capital structure "would be viewed by the rating agencies as constructive and equitable." Tr. vol. 11, 619-20. Witness D'Ascendis also testified that economic conditions in North Carolina, which deteriorated in the first half of 2020 as a result of the COVID-19 pandemic, remain highly correlated to the overall conditions nationwide. *Id*. at 626. Witness D'Ascendis noted that "[f]rom January 2016 through June 2020, the average authorized ROE for vertically integrated electric utilities was 9.74 percent, 14 basis points above the Stipulated ROE. Of the 107 cases decided during that period, 64 (i.e., nearly 60.00 percent) included authorized returns of 9.60% or higher." Tr. vol. 11, 621. He concluded that the 9.60% stipulated ROE is "a reasonable resolution of an otherwise contentious issue." *Id*. at 620.

Public Staff Settlement Testimony

Witness Woolridge testified that he found the cost of capital components reasonable within the context of the overall settlements and in resolution of most of the issues in the proceeding. Tr. vol. 15, 691-92. He noted that the stipulated ROE was a compromise for each party, a reduction from the Company's last authorized ROE of 9.90%, below the 9.67% average authorized ROE for vertically integrated electric utilities during the first half of 2020, and the lowest ROE authorized for a vertically integrated investor-owned electric utility in North Carolina in at least the last 30 years. *Id*. at 695.

Hearing Testimony

Under cross-examination by the AGO witness D'Ascendis noted that measures of volatility had fallen since March but remained high and were expected to continue to remain high. Consolidated Tr. vol. 2, 43-44. Witness D'Ascendis further testified that the North Carolina economy's response to the pandemic was highly correlated with that of the country but that the effect had been somewhat less severe and the recovery had been somewhat more rapid. He concluded that North Carolina was somewhat less effected by the recession than the nation as a whole. Consolidated Tr. vol. 1, 125-26.

Public Witness Testimony and Consumer Statements of Position

The Commission also received numerous statements of consumer position regarding this docket, many of which expressed concern about DEP's proposed rate increase. The Commission held five evening hearings throughout the Company's North

Carolina service territory to receive public testimony. A total of 58 individuals testified and several testified that the rate increase was not affordable for many customers, including those on fixed incomes, the elderly, person with disabilities, the unemployed and underemployed, and the impoverished.

Law Governing the Commission's Decision on ROE

The ROE is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which the Second Partial Stipulation and the other intervenor settlements have been reached. In the absence of a settlement agreed to by all the parties, the law of North Carolina requires the Commission to exercise its independent judgment and arrive at its own independent conclusion as to the proper ROW. *See, e.g., CUCA I,* 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the ROE, the Commission must evaluate the available evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (*Cooper I*).

The baseline for establishment of an appropriate ROE are the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission,* 262 U.S. 679 (1923) (*Bluefield*), and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish:

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [an ROE], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

2018 DEC Rate Order at 50; s*ee also, State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

The ROE is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital:

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the

> investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). "The term 'cost of capital' may [also] be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., *The Regulation of Public Utilities* (Public Utilities Reports, Inc. 1993), at 388.

Long-standing decisions of the North Carolina Supreme Court have recognized that the Commission's subjective judgment is a necessary part of determining the authorized ROE. *State ex rel. Utils Comm'n v. Public Staff-N.C. Utils. Comm'n,* 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988) (*Public Staff*). Likewise, the Commission has observed as much in exercising its duty to determine the ROE, noting that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:

> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable . . . . It is the task of the commissions to translate these generalizations into quantitative terms.

Charles F. Phillips, Jr., *The Regulation of Public Utilities,* 3d ed. 1993, 381-82. (Notes omitted.)

Order Granting General Rate Increase, *Application of Carolina Power & Light Co., d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023, at 35-36 (N.C.U.C. May 30, 2013), *aff'd*, *State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Order).

Moreover, in setting rates the Commission must not only adhere to the dictates of both the United States and North Carolina Constitutions, but as has been held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff,* 323 N.C. at 490, 374 S.E.2d at 370. Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the ROE element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the ROE. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates and adjusted for proven changes occurring up to the close of the expert witness hearing) is but one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. *See* N.C.G.S. § 62-133. North Carolina General Statute § 62-133(b)(4) provides, in pertinent part, that the Commission shall:

> [f]ix such rate of return on the cost of the property . . . as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing ROE-related factors — the economic conditions facing the Company's customers and the Company's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the ROE, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the analyses conducted by the expert witnesses on ROE, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. 2013 DEP Rate Order at 38. Further,

> [t]he Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on common equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37. Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the ROE, just as the Commission must assess the impact of economic conditions on customers' ability to pay for service, it likewise must assess the effect of regulatory lag[6] on the Company's ability to access capital on reasonable terms.

[6] Regulatory lag can cause a utility's realized, earned return to be less than its authorized return, negatively affecting the shareholder's return on investment as other expenses and debts owed are paid ahead of investor return.

The Commission sets the ROE considering both of these impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible to the benefit of the customers without impairing the Company's ability to attract the capital needed to provide safe and reliable electric service and recover its cost of providing service.

Discussion and Application of Law to the Facts

The Commission has examined the Company's Application and supporting testimony and exhibits and Form E-1 filings seeking to justify its requested increase. DEP's updated request prior to entering into the Stipulations and including the May 2020 Updates was a retail revenue increase of approximately $569.7 million in annual revenues. DEP and the Public Staff, who in this docket represents all users and consumers of the Company's electric service, entered into a stipulation on ROE and capital structure that resulted in reducing the retail revenue increase sought by the Company by $59.3 million. Smith Second Settlement Ex. 3. CIGFUR, the Commercial Group, and Harris Teeter each entered into a separate stipulation that, as amended, accepted a 9.60% ROE, subject to certain conditions. As with all settlement agreements, each party to the stipulations gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEP's Application, it is apparent that the stipulations tie the 9.60% ROE to substantially agreed upon concessions made by DEP. As noted above, since the AGO and CUCA, as well as other parties that did not provide testimony on ROE, did not agree to the settlements the Commission is required to examine the Stipulations and exercise its independent judgment to arrive at its own independent conclusion as to the proper ROE.

The starting point for an examination of what constitutes a reasonable ROE begins with the various economic and financial analyses provided by the parties' expert witnesses. In this proceeding those analyses were provided in the testimonies of six different witnesses. These testimonies, as summarized above, provide a relatively broad range of methods, inputs, and recommendations regarding the proper ROE determination for DEP. For example, witness D'Ascendis relied in his direct testimony on multiple analyses to arrive at his ROE recommendation. These analyses were a Constant Growth DCF Analysis, a Capital Asset Pricing Model analysis, an Empirical Capital Asset Pricing Model, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. By way of comparison, Public Staff witness Woolridge and AGO witness Baudino relied upon DCF analyses and CAPM analyses in reaching their conclusions; however, the inputs utilized by these witnesses in their analyses are different from those utilized by witness D'Ascendis. Commercial Group witness Chriss recommended that the Commission look at the proposed ROE in light of recent ROEs approved by the Commission and by commissions nationwide. Similarly, CIGFUR witness Phillips looked at the average allowed ROEs for both vertically integrated and distribution-only electric utilities of 9.73% and recommended that average as a cap to the allowed ROE. Finally, CUCA witness

O'Donnell proposed an ROE of 8.75% using the DCF and CAPM methodologies, as well as a comparable earnings approach.

These varying analyses, as is typical, produced varying results. Witness D'Ascendis' analyses prompted him to propose an ROE range of 10.00% to 11.00% with a specific ROE recommendation of 10.50%. Witness Woolridge's analyses resulted in a recommended ROE range of 6.70% to 8.40% with a primary recommendation of a 9.00% ROE with a 50% common equity and 50% debt capital structure and a secondary recommendation of an 8.40% ROE if DEP's proposed capital structure of 47.00% long-term debt and 53.00% common equity was approved. AGO witness Baudino proposed an ROE of 9.00%. Finally, as noted above, witness O'Donnell recommended a ROE of 8.75%, and witness Phillips a cap on ROE of 9.73%.

The Commission finds the cost of equity analyses helpful in reaching its conclusion on an appropriate ROE for DEP but notes that the outputs of the various analyses span a range from 6.70% to 15.70% and the specific ROE (primary) recommendations of the witnesses span a range from 8.75% on the low end to 10.50%[7] on the high end.

The Commission finds that the updated DCF, Bond Yield Risk Premium, and Expected Earnings analyses of DEP witness D'Ascendis, the Second Partial Stipulation, and the other intervenor settlements are credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis in his supplemental rebuttal testimony provided his constant growth DCF analyses, as shown on Supplemental Rebuttal Ex. DWD-1, pages 1 and 2 as follows: 30-day dividend yield high ROE mean 9.67%, median 9.42%; and 90-day dividend yield high ROE mean 9.57%. The Commission finds witness D'Ascendis' constant growth DCF analyses mean and median ROE results credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis' updated Bond Yield Plus Risk Premium, as shown on Supplemental Rebuttal Ex. DWD-5, using the current 30-year Treasury yield of 1.47%, the near term projected 30-year Treasury yield of 1.72%, and the long-term projected Treasury yield of 3.40% and applying it to the approved ROEs in 1,630 electric utility rate proceedings between January 1980 and June 30, 2020, results in ROEs of 10.25%, 10.08%, and 9.96%, respectively. While in the past, the Commission has generally approved the use of current interest rates rather than projected near-term or long-term interest rates in this particular case disequilibrium in the current markets as discussed by witness Woolridge give the Commission reason to look beyond the current Treasury yields and give some weight to projected rates. The Commission finds witness D'Ascendis' updated Bond Yield Plus Risk Premium analyses using the current and

[7] As noted *infra*, DEP witness D'Ascendis recommended an ROE of 10.50% but DEP requested a lower ROE of 10.30% to mitigate the impact of the rate increase on customers.

projected 30-year Treasury yields to be credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis' Expected Earnings approach produced a range from 5.50% to 13.56% with a mean of 10.18% and a median of 10.55%. Supplemental Rebuttal Ex. DWD-6. In prior cases, the Commission has given weight to this methodology, which stands separate and apart from the market-based methodologies (e.g., the DCF or CAPM) also used by ROE experts. *See, e.g*., 2013 DEC Rate Order at 36. The Commission chooses to do so again in this case.

In this case the Commission is concerned that the ROE recommended by CUCA witness O'Donnell, and to a lesser extent the ROE recommended by AGO witness Baudino, would, when translated into rates and holding all other things equal, fail the *Hope* "end results" test. This is shown graphically in Chart 1 of D'Ascendis' Rebuttal Testimony. Tr. vol. 11, 354. The Commission agrees with witness D'Ascendis that this could result in investors receiving a lower return with greater risk than would be available from other utilities, thereby making it more costly to raise capital. The Commission agrees with witness D'Ascendis that the ROE recommendations of witnesses Baudino and O'Donnell are unduly low, places great weight upon this observation, and therefore finds the Baudino and O'Donnell ROE recommendations to be unpersuasive. In doing so, the Commission emphasizes that it is referencing the data concerning other authorized ROEs as a means to test the ROE recommendations of witnesses Baudino and O'Donnell, and not as a reference to or reliance upon the doctrine of "gradualism." *See Cooper II*, 367 N.C. at 443.

Witnesses Baudino and O'Donnell recommended ROEs of 9.00%, and 8.75%, respectively. These recommendations are below the band of authorized ROE results set out in D'Ascendis' Chart 1. These recommendations are also below the stipulated 9.90% ROE from the Company's previous rate case or 10.20% from the rate case prior to that. The recommendations of witnesses Baudino and O'Donnell are also inconsistent with those recently authorized in North Carolina. The Commission has most recently authorized an ROE of 9.75% for Dominion Energy North Carolina; 9.90% for the Company and DEC in their prior rate cases, 9.70% for Piedmont Natural Gas, and 9.40% for Aqua America. Witness D'Ascendis indicated, and the Commission agrees, that these witnesses' recommendations are far below the average and median ROE for vertically integrated electric utilities in jurisdictions rated in the top third by Regulatory Research Associates, which range from 9.37% to 10.55%. Witnesses Baudino and O'Donnell's recommendations are below those of other vertically integrated utilities similarly rated from 2015 through 2020, while the settled ROE of 9.60% does fall within that ROE range.

In his direct testimony, witness Baudino testified that his 9.00% ROE recommendation was "reasonably close to recently allowed ROEs", using a 9.68% average ROE determination by commissions in 2017 as "recently allowed ROEs." Witness Baudino contended on cross-examination that "[this 68-point differential] was reasonable." Tr. vol. 2, 136. The differential between the stipulated ROE (9.60%) and witness Baudino's 9.00% ROE recommendation is 60 basis points – less than the 68 basis points witness Baudino deemed "reasonable."

There are other aspects of these witnesses' analyses that the Commission finds lacking. For example, the Commission finds questionable witness Baudino's failure to adjust his ROE recommendation in his supplemental direct testimony considering the recent volatility in the markets, increase in betas for the companies in the proxy group, and the higher DCF results in his supplemental testimony. Additionally, the Commission agrees with witness D'Ascendis' criticism of witness Baudino's growth rates applied to the Constant Growth DCF model, and his reliance on the Constant Growth DCF model to determine the Company's ROE, as well as the reasonableness of his Bond Yield Plus Risk Premium analysis among other factors. Finally, the Commission also gives no weight to witness Baudino's CAPM approach as witness Baudino himself disregarded its unreasonably low results.

Regarding the ROE recommendation of CUCA witness O'Donnell, like with witness Baudino, his reliance on historical growth rates in his DCF analysis does not adequately encapsulate how the model is a forward-looking measure of investors' expectations. Further, the Commission finds compelling witness D'Ascendis' test of the relationship between retention ratios and future growth rates demonstrating that earnings growth actually *decreased* as the retention ratio increased, thereby undermining the premise underlying witness O'Donnell's use of the Retention Growth Model. As for witness O'Donnell's Comparable Earnings Approach, his forward-looking 2019 and 2022–2025 analysis yielding ROE estimates of 10.0% to 10.6% for his proxy group was similar to witness D'Ascendis' updated Expected Earnings analysis of 10.18% to 10.55%. Overall, it seems that witness O'Donnell's 8.75% ROE estimate is at odds with the data he presented.

Additionally, witness D'Ascendis testifies that the intervenor witnesses fail to recognize the risks faced by the Company and do not appropriately reflect the evolving capital market environment. Tr. vol. 11, 351. A significant departure from the authorized ROEs of other similarly situated utilities impacts the Company's ability to compete with other companies for long-term capital to provide safe and reliable utility service. The Commission notes the risk that an ROE in the range recommended by witnesses Baudino and O'Donnell could impact the Company's ability to compete for capital, as illustrated by witness D'Ascendis in his discussion of a recent rate decision in which the financial community responded negatively to an adverse regulatory outcome for CenterPoint Energy Houston Electric.

In sum, and in light of all of the factors discussed in this Order, the Commission places minimal weight upon the ROE recommendations of witnesses O'Donnell and Baudino. Rather, the Commission finds the stipulated ROE to be reasonable and appropriate, as well as supported by the substantial weight of the evidence presented. As witness D'Ascendis notes in his second settlement testimony, the average authorized ROE for vertically integrated electric utilities from 2016 to June 2020 was 9.74%, 14 basis points above the stipulated ROE.

The Commission, of course, does not blindly follow ROE results allowed by other commissions. The Commission determines the appropriate ROE based upon the evidence and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some consideration, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that an ROE significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while an ROE significantly higher than other utilities of comparable risk would result in customers paying more than necessary. Both of those outcomes are undesirable and would result in unjust and unreasonable rates. The fact that the approved ROE falls 14 basis points below the average and within the range of recently approved ROEs for other vertically integrated electric utilities lends additional support to the Commission's approval.

DEP witness D'Ascendis in his supplemental rebuttal testimony provided his constant growth DCF analyses, as shown on Supplemental Rebuttal Ex. DWD-1, pages 1 and 2: 30-day dividend yield high ROE mean 9.67%, median 9.42%; and 90-day dividend yield high ROE mean 9.57%. Although the Commission does not approve of witness D'Ascendis' using only analysts' predicted earnings per share to determine the DCF growth rate, the Commission finds witness D'Ascendis' constant growth DCF analyses mean and median ROE results to be credible, probative, and entitled to substantial weight.

DEP witness D'Ascendis' updated Bond Yield Plus Risk Premium, as shown on Supplemental Rebuttal Ex. DWD-5, using the current 30-year Treasury yield of 1.47%, the near term projected 30-year Treasury yield of 1.72%, and the long-term projected Treasury yield of 3.40% and applying it to the approved ROEs in 1,630 electric utility rate proceedings between January 1980 and June 30, 2020, results in ROEs of 10.25%, 10.08%, and 9.96%, respectively. While in the past the Commission has generally approved the use of current interest rates rather than projected near-term or long-term interest rates, in this particular case current disequilibrium in the market gives the Commission reason to look beyond the current Treasury yields and give some weight to projected rates. The Commission finds witness D'Ascendis' updated Bond Yield Plus Risk Premium analyses using the current and projected 30-year Treasury yields to be credible, probative, and entitled to substantial weight.

The record contains substantial evidence supporting the reasonableness of the stipulated ROE of 9.60%. The Commission notes generally that this ROE is well within the range of recommended returns by the economic experts in this docket of 8.75% to 10.50%. More specifically, an ROE of 9.60% falls within D'Ascendis' range under his constant growth DCF analyses and his Expected Earnings Analysis. Supplemental Rebuttal Ex. DWD-6. In prior cases, the Commission has given weight to this methodology, which stands separate and apart from the market-based methodologies (*e.g.,* the DCF or CAPM) also used by ROE experts. *See, e.g.*, 2013 DEC Rate Order at 36. The Commission chooses to do so again in this case. Moreover, 9.60% falls squarely within the range and very close to the average of recently allowed ROEs for vertically integrated electric utilities nationally. Lastly, the Commission notes that the stipulated ROE is 70 basis points lower than the ROE the Company requested in its Application. As such, the Commission concludes that 9.60% is within the "zone of reasonableness" that leading commentators and the North Carolina Supreme Court have indicated is presumptively just and reasonable. *See State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the Southeast*, 285 N.C. 671, 681 (1974) (a "zone of reasonableness extending over a few hundredths of one percent" exists within which the Commission may appropriately exercise its discretion in choosing a proper ROE).

As the Supreme Court made clear in *CUCA I* and *CUCA II*, the Commission should give full consideration to a nonunanimous stipulation itself, along with all evidence presented by other parties, in determining whether the stipulation's provisions should be accepted. In this case, insofar as expert ROE testimony is concerned, both witness D'Ascendis and witness Woolridge support an ROE at 9.60%. Tr. vol. 11, 620 (D'Ascendis); tr. vol. 15, 695-96 (Woolridge). The Commission notes that the other intervenor settlements, as amended, also supported the use of an ROE of 9.60%. Only witness Baudino questioned the settlement ROE. Tr. vol. 2, 133. But, as discussed above, the Commission places very little weight upon his ROE recommendation. Thus, the Commission finds and concludes that the Second Partial Stipulation, the other intervenor settlements as amended, along with the expert testimony of witnesses D'Ascendis and Woolridge, is credible evidence of the appropriate ROE and is entitled to substantial weight in the Commission's ultimate determination of this issue.

In summary, the Commission concludes there is substantial evidence supporting the reasonableness of an ROE of 9.60%.

However, to meet its obligation in accord with the holding in *Cooper I*, the Commission will next address the impact of changing economic conditions on customers. In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses D'Ascendis, Woolridge, and Baudino, which the Commission finds entitled to substantial weight, addresses changing economic conditions at some length. Witness D'Ascendis provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are "highly correlated" with conditions in the broader nationwide economy. As such, witness D'Ascendis testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his ROE estimates.

Public Staff witness Woolridge agreed with DEP witness D'Ascendis that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. He pointed out that at the time of the filing of his testimony that while the unemployment rates in North Carolina and DEP's service territory have fallen since their peaks in the 2009-2010 period, they are both above the national average of 3.90%. Witness Woolridge also noted that while North Carolina's residential electric rates are below the national average, its median household income is more than 10% below the U.S. norm.

Yet subsequent to the filing of this case, and as a result of the COVID-19 pandemic, economic conditions deteriorated in North Carolina and across the country during the first half of 2020. The Commission gives weight to the testimony of witness Baudino regarding the national decline of the GDP in the first quarter of 2020 by 5.0% as unemployment rose to 12.90% and 13.30% in in May in North Carolina and the US, respectively. The Commission likewise gives weight to the testimony of witness D'Ascendis regarding the national and State unemployment rates in July of 10.2% and 8.5%, respectively, reflecting a quick rebound of at least some of the economic activity lost during the downturn.

As the Commission has noted, customer impact due to changing economic conditions is embedded in ROE expert witness analyses. For example, Witness D'Ascendis' analysis, which the Commission credits and to which the Commission gives weight, also indicates that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the allowed ROE. Witness D'Ascendis' testimony regarding correlation between U.S. and North Carolina GDP growth for the fifteen years and four quarters ended March 2020, and employment in the US and DEC's service territories from February to May 2020, demonstrate these high correlations. The Commission also observes that witness D'Ascendis' testimony that North Carolina's economy had been affected somewhat less severely than the national economy and its economic recovery had been somewhat more rapid.

Therefore, the Commission determines that the econometric data relied upon by ROE expert witnesses sufficiently captures the effects and impacts of changing economic conditions upon customers.

Based upon the general state of the economy and the need for the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the stipulated ROE of 9.60% will not cause undue hardship to customers even though, the Commission acknowledges, some customers will struggle to pay for electric utility service.

Many of the adjustments to the Company's proposed rate increase reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.[8] For example, to the extent the Commission made

[8] The Commission notes that consumers pay "rates," a charge in cents per kilowatt-hour (kWh) for the electricity they consume. They do not pay a "rate of return on common equity," though it is a component of the Company's cost of providing service, which is built into the charge per kWh. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the ROE in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.60%.

downward adjustments to rate base, disallowed test year expenses, increased test year revenues, or reduced the equity capital structure component, the Commission reduced the rates consumers will pay during the future period when rates will be in effect. In this case, the Commission has ordered negative adjustments to many expenses sought to be included in the Company’s revenue requirement. Because the compensation owed to investors for investing in the Company’s provision of service to consumers takes the form of return on investment, downward adjustments to rate base, disallowances of test year expenses, increases to test year revenues, or reduction in the equity capital structure component will reduce investors’ return on investment irrespective of the determination of ROE.

The Commission has also approved herein an annual $2.5 million shareholder contribution to the Neighbor Energy Fund in 2021 and 2022, as provided in the Second Partial Stipulation, and an annual contribution of $3 million, in conjunction with DEC, to the Helping Home Fund in 2021 and 2020, for a total contribution of $11 million of the Company's shareholder funds for energy assistance to low-income customers. NCSEA/NCJC et al. Stipulation, § IV. These decisions directly benefit customers with the least ability to pay in the current economic environment. The Commission takes these facts into account when approving the 9.60% ROE.

The Commission also recognizes that the Company is in a significant construction mode, and much of the associated investment is for generation, transmission, and distribution infrastructure to benefit DEP’s customers, as well as in response to recent increases in environmental compliance costs and other operating expenses. The need to invest significant sums to serve its customers requires the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on DEP’s customers against the benefits that those customers derive from the Company’s ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina. Thus, the Commission finds and concludes that such capital investments by the Company provide significant benefits to all of DEP’s customers.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.60% ROE is supported by the greater weight of the evidence and should be adopted. The hereby approved ROE appropriately balances the benefits received by DEP’s customers from DEP’s provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to the Company’s ability to compete in the equity capital market to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DEP’s customers will experience in paying DEP’s adjusted rates. The Commission further concludes that a 9.60% ROE will allow DEP to compete in the market for equity capital, providing a fair return on investment to its investor-owners, and that the lowering of the rate from the requested 10.30% to 9.60% has the effect of lowering the cost of service which forms the basis of the rates the ratepayers must pay for service. Accordingly, the Commission concludes, accounting for changing economic conditions and their impact on customers, that the approved ROE will result in the lowest rates constitutionally permissible in this proceeding.

Finally, in approving the 9.60% ROE, the Commission gives significant weight to the stipulations and the benefits that they provide to DEP's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holding in *CUCA I*.

As a result, the Commission concludes that the 9.60% stipulated ROE is reasonable and appropriate and is supported by the greater weight of the substantial evidence in the record.

B. Capital Structure

Summary of the Evidence

In DEP's Application witness Newlin proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. vol. 11, 633. Witness Newlin testified that the Company's "specific debt/equity ratio will vary over time, depending on a variety of factors, including among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company." *Id.* at 648. As of December 31, 2019, DEP's capital structure was 52% common equity and 48% long-term debt. *Id.* at 661.

In his direct testimony CUCA witness O'Donnell recommended that the Commission reject the Company's capital structure proposal and instead advocated for a 50/50 capital structure. Tr. vol. 14, 133. Witness O'Donnell's analysis supporting his 50/50 capital structure recommendation was based on his comparison of capital structures of publicly traded holding companies, not operating utility companies. *Id*. at 237-38.

Public Staff witness Woolridge testified that the Company's proposed capital structure included more common equity than the average of the proxy group he used in conducting his analysis. Tr. vol. 15, 563. He stated that it is appropriate to use the common equity ratios of the parent holding companies and that the high debt ratio and low equity ratio of DEP's parent company, Duke Energy, is credit negative for DEP as evaluated by Moody's. *Id*. at 566-67. He noted, however, that because DEP is a regulated business, it is exposed to less business risk and can carry relatively more debt in its capital structure than most unregulated companies, like Duke Energy. *Id*. at 569. Witness Woolridge further testified that DEP should take advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements. *Id*. at 569. Therefore, witness Woolridge recommended a 50/50 capital structure based on a 9.00% ROE. *Id*. at 571. Witness Woolridge also made an alternative capital structure recommendation of the Company's proposed structure of 47% long-term debt and 53% common equity based on an 8.40% ROE. *Id*. at 572.

AGO witness Baudino recommended that the Commission reject the Company's requested ratio and instead recommended the Commission approve the Company's December 2018 capital structure, which includes a common equity of 51.50%. Tr. vol. 13, 445, 511. As noted above, witness Baudino's recommendation is lower than the Company's recent actual capital structure of 52% equity and 48% long-term debt.

In rebuttal witness Newlin pointed out that CUCA witness O'Donnell utilized data showing capital structures that were inappropriate to use because they do not differentiate between various types of utility companies, which present different risk profiles. Tr. vol. 11, 661. Witness D'Ascendis testified that parent and operating companies do not necessarily have the same capital structures because financing at each level is driven by "the specific risks and funding requirements associated with their individual operations." *Id*. at 469. He noted the Commission's previous rejection of the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. *See* Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142, at 87-88 (Feb. 23, 2018) (2018 DEP Rate Order), *aff'd in part, and remanded in part*, *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (2020); Order Granting General Rate Increase and Approving Amended Stipulation, *Application of Duke Energy Carolinas, LLC, for an Increase in and Revisions to Its Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 909, at 27-28 (Dec. 7, 2009) (2009 DEC Rate Order).

In addition witness D'Ascendis noted the use of the operating subsidiary's actual capital structure – that is, the capital actually funding the utility operations that provide service to customers – is entirely consistent with precedent of the Federal Energy Regulatory Commission (FERC), so long as three criteria are met: the operating subsidiary (1) issues its own debt without guarantees; (2) has its own bond rating; and (3) has a capital structure within the range of capital structures for comparable utilities. *Id*. at 483-84. Witnesses Newlin and D'Ascendis testified that DEP, which issues its own debt and has its own bond rating, has a capital structure that is generally consistent with that of other operating companies, especially vertically integrated companies. *Id*. at 673 (Newlin); *id*. at 568 (D'Ascendis). Further, in response to witness O'Donnell, witness D'Ascendis testified that by excluding equity ratios authorized in jurisdictions that include non-investor supplied capital in the capital structure, witness O'Donnell's review demonstrated an average and median authorized equity ratio in 2019 of 52.08% and 52% for vertically integrated utilities. *Id*. at 568. Thus, he noted that the stipulated 52% equity ratio is consistent with authorized equity ratios. *Id*. at 624. DEP witness Newlin also pointed out that witness O'Donnell considers jurisdictions in which non-investor supplied capital is included in the capital structure, thus biasing his review. *Id*. at 660.

Subsequent to the filing of testimony, the Company reached several stipulations with the Public Staff, CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. agreeing that the rates in this proceeding should be set using a capital structure of 52% common equity and 48% long-term debt, including in the Public Staff's

Second Partial Stipulation. The 52% equity capital structure agreed to in these settlement agreements represent a compromise between the Company's 53% equity position and the intervenors' recommendations ranging from a 50% to a 51.50% equity capital structure.

In their testimony supporting the stipulations Company witness Newlin and Public Staff witness Woolridge testified that the capital structure reflected in the Second Partial Stipulation represents a compromise by both parties in an effort to reach agreement and is in the public interest. Witness De May's second settlement testimony also supported the stipulated 52% equity capital structure. Tr. vol. 11, 794.

Discussion and Conclusions

In evaluating the evidence on capital structure in this proceeding the Commission first notes that the equity/debt ratios reflected in the Second Partial Stipulation and the stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. of 52% equity and 48% long-term debt are consistent with and within the prior decisions of the Commission.[9] That consistency is not a determinative factor from the Commission's perspective but the prior decisions do provide some context supporting the reasonableness of the stipulated capital structure.

Based upon its own review and independent analysis of the evidence the Commission concludes that a capital structure of 52% equity and 48% long-term debt, as is reflected in Section III.B of the Second Partial Stipulation and the stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. is just and reasonable and appropriate for use in this proceeding on several grounds.

First, this capital structure is the same capital structure authorized for DEP in its last rate case. Second, this capital structure was accepted by the Public Staff, CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. in separate stipulations. Third, the Commission gives great weight to Company witness Newlin's testimony that the stipulated capital structure is reasonable and appropriate when viewed in the context of the overall Second Partial Stipulation. Fourth, the Commission places great weight as well on witness Woolridge's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement. Fifth, the Commission also gives weight to the Second Partial Stipulation and the benefits that it provides to DEP's customers, which the Commission is obliged to consider as an independent piece of evidence under *CUCA I* and *II*. Each party to the Second Partial Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on the Application and prefiled testimony, it is apparent that the

[9] *See* DENC Sub 532 Order (51.75% common equity and 48.25% debt); PSNC Sub 565 Order (52.0% common equity, 44.62% long-term debt, 3.38% short-term debt); PNG Sub 743 Order (52.00% equity, 47.15% long-term debt, 0.85% short-term debt); DEC Sub 1146 Order (52% common equity and 48% long-term debt); DEP Sub 1142 Order (52% common equity and 48% long-term debt); DENC Sub 562 Order (52% common equity and 48% long-term debt).

Second Partial Stipulation ties the 52% equity and 48% long term debt capital structure to substantial concessions the Company made to reduce its revenue requirement. Sixth, and finally, the Commission gives weight to the stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. as it did to the Second Partial Stipulation.

Accordingly, based on the matters set forth above and in the exercise of its independent judgment, the Commission finds that a preponderance of the evidence weighs in favor of the stipulated capital structure pursuant to Section III.B of the Second Partial Stipulation and the stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA and NCJC et al. and that such capital structure is just, reasonable, and appropriate for use in setting rates in this docket.

C. Cost of Debt

DEP witness Newlin testified that the Company's long-term debt cost as of December 31, 2018, was 4.15%, which was the value used to determine the revenue requirement in the Company's Application. As part of Section III.B of the Second Partial Stipulation, DEP and the Public Staff agreed to use in determining the revenue requirement the May 2020 embedded cost of debt of 4.04%. The Commission finds for the reasons set forth herein that 4.04% cost of debt is just and reasonable.

In his direct testimony Public Staff witness Woolridge initially proposed a cost of long-term debt of 4.11%, DEP's long-term debt cost as of December 31, 2019, and DEP thereafter updated its cost of debt to 4.11% in supplemental testimony filed July 10, 2020. Tr. vol. 15, 696. As part of the give-and-take negotiations involved in the settlement process, DEP and the Public Staff agreed to a cost of long-term debt of 4.04%, DEP's long-term debt cost updated through May 2020. *Id.*

No intervenor offered any evidence to contradict the use of 4.04% as the cost of debt. The Commission therefore finds and concludes that the use of a debt cost of 4.04% per the terms of Section III.B of the Second Partial Stipulation is supported by the greater weight of the substantial evidence and is just and reasonable to all parties in light of all the evidence presented.

D. Credit Metrics

Summary of the Evidence

DEP Direct Testimony

Witness Newlin

DEP witness Newlin testified that his responsibilities as Senior Vice President, Corporate Development and Treasurer for Duke Energy include managing Duke Energy and its subsidiaries' credit ratings and interactions with major credit rating agencies. His testimony addressed DEP's financial objectives, capital structure, cost of capital, credit ratings, and forecasted capital needs. Witness Newlin emphasized the importance of DEP's continued ability to meet its financial objectives. He stated that the Company's proposed rate increase will allow it to recover prudently incurred costs, compete in the capital markets for needed capital, and preserve its financial standing with both debt and equity investors, as well as the credit rating agencies, to the long-term benefit of its customers. Tr. vol. 11, 628-631.

Witness Newlin testified that DEP has substantial capital needs over the next several years and that financial strength and access to capital at all times are necessary for DEP to provide service to its customers. To maintain its financial strength and flexibility, including its strong investment grade credit ratings, DEP has specific objectives including: (1) maintaining at least 53 percent common equity; (2) ensuring timely recovery of prudently incurred costs; (3) maintaining sufficient cash flows to meet obligations; and (4) maintaining a sufficient return on common equity to fairly compensate shareholders. *Id*. at 631.

Witness Newlin explained credit quality and credit ratings and how they are determined by the two major credit ratings agencies, Standard & Poor's (S&P) and Moody's Investor Service (Moody's). In assessing credit quality, these agencies consider many qualitative and quantitative factors in assigning credit ratings. Qualitative factors may include DEP's regulatory climate, its track record for delivering on commitments, strength of management, its operating performance, and the economic vitality and customer profile of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which DEP maintains financial leverage in relation to its generation of cash and its ability to meet its fixed obligations based on internally generated cash, such as its debt to capital ratio. Witness Newlin also provided the credit ratings by S&P and Moody's on DEP's outstanding debt, as of October 30, 2019, which show that DEP carries a credit rating compatible with strong, investment-grade securities, subject to low risk for an investor. *Id*. at 634-35.

However, according to his testimony the ratings agencies have identified several challenges that DEP faces in maintaining its current credit ratings. These include downward pressure on credit metrics due to regulatory lag in the recovery of coal ash basin closure costs, reduced cash flows due to federal tax reform, and elevated capital expenditures. He elaborated that the Federal Tax Cut and Jobs Act of 2017 (Tax Act) resulted in electric utilities, including DEP, and their holding companies losing some of their cash flow from deferred taxes on an ongoing basis. He testified that this loss of cash flow would reduce DEP's funds from operations to debt ratio (FFO/Debt), a key credit metric. Because DEP's EDIT are customer-supplied funds, he testified that DEP proposes to flow the EDIT, not subject to a statutory required flowback period, over twenty years. In his opinion, a twenty-year period balances both the interest of customers and the financial strength of the Company and would smooth out the reduction in cash flow to DEP as it returns the EDIT to customers. *Id*. at 637-45.

Public Staff Testimony

Witness Hinton

Public Staff witness Hinton testified to address concerns raised by Company witnesses Newlin and De May with regards to the credit metrics and the risk of a downgrade of DEP's credit ratings. He also testified in support of the Public Staff's recommended flowback of unprotected EDIT over a five-year period. Tr. vol. 17, 324.

Witness Hinton testified that DEP had provided the Public Staff with projected FFO/Debt credit metrics using both the five-year flowback period for unprotected EDIT recommended by the Public Staff and the twenty-year flowback recommended by DEP. He noted that in Moody's March 28, 2019, Credit Opinion for DEP, an FFO/Debt metric that is between 21% to 23% qualifies for an "A" rating. He testified that the FFO/Debt metric would only be below 21% in 2020 with a five-year flowback. In his opinion, a temporary decrease in FFO/Debt would not likely lead to a downgrade of the Company's "Aa3" ratings on its first mortgage bonds or its "A2" senior unsecured bonds. Based on his analyses, he believed that unexpected financial developments would have to occur that reduced DEP's cash flow from operations or caused the Company to issue more debt to trigger a downgrade. In addition, he testified that Moody's and S&P place weight on factors other than credit metrics and that DEP has other means to finance the EDIT flowback over the five-year period, such as equity. Finally, witness Hinton testified that even if DEP were to be downgraded by one notch to "A3," it is reasonable to expect that the investor-required bond yield would increase by 10 basis points under current market conditions. *Id*. at 324-31.

DEP Rebuttal Testimony

Witness Newlin

In rebuttal DEP witness Newlin testified that he disagreed with Public Staff witness Hinton's advocacy for a five-year flowback of unprotected EDIT instead of the twenty-year period proposed by the Company. He stated that reducing the Company's cash flow through a more accelerated flowback of unprotected EDIT at the same time that DEP is investing in large capital projects and refinancing obligations will negatively impact its credit metrics, which must be taken into account. Witness Newlin noted that in March 2020, Moody's in its Credit Opinion of DEP identified tax reform as one of the several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios). Tr. vol. 11, 678-79.

Witness Newlin testified that it is reasonable that customers should benefit from the Tax Act. However, he submitted that without the Commission's thoughtful consideration regarding all aspects of the Tax Act, particularly through a reduction in cash flow, the Company's credit quality could be adversely affected. He stated that an accelerated return of EDIT over an arbitrary five-year period would adversely impact the Company's cash flow and FFO/Debt ratio. Furthermore, witness Hinton's analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other credit negative proposals by the Public Staff including a lower return on equity, a more leveraged capital structure, disallowance of a return on coal ash costs, and other recommendations for ratemaking that would reduce cash flows and increase debt. *Id*. at 680-82.

Witness Newlin also testified that witness Hinton's estimate of a 10-basis point increase in debt cost as a result of a downgrade is based on capital market conditions reflecting historically low interest rates and near record tight credit spreads. He testified that credit spreads can widen significantly during periods of uncertainty and market volatility. Witness Newlin noted that Moody's mentions a downgrade would occur if FFO/Debt is below 20% on a sustained basis. However, witness Newlin testified that an upgrade would require significantly higher metrics and would require approximately $250 million in incremental annual cash flows on a sustained basis with no additional leverage to achieve a 25% FFO/Debt ratio which would likely require significant rate increases over prolonged periods. *Id*. at 685-87.

Witness Young

DEP witness Steven Young, Executive Vice President and Chief Financial Officer for Duke Energy, testified in rebuttal on the financial needs of Duke Energy investors, the impact of utility regulation on the Company's credit profile and investors, the benefits to customers of having a financially healthy utility, the Company's concerns with some of the proposals offered by intervenors in this proceeding (and with the Commission's recent Dominion Energy North Carolina Order issued in Docket No. E-22, Sub 562 and Sub 566), and the reasons those proposals should not be adopted by the Commission in this proceeding. Tr. vol. 11, 702-03.

Witness Young testified that neither Duke Energy nor DEP has access to any established "reserves" to pay the carrying costs of unavoidable debt (and supply equity) needed to support utility operations. He testified that having to simply absorb those carrying costs could have significant negative implications to the financial stability of the enterprise as a whole. Witness Young explained that energy utility operations are often cash flow negative due to the need to serve a growing customer base, repair and maintain existing infrastructure, and immediately respond to all service interruptions such as those caused by major storms. Duke Energy's ability to fund these investments is based upon investor confidence that customer rates will be set at levels that allow all prudent utility operating and financing costs to be recovered. *Id*. at 705-07.

Witness Fetter

DEP rebuttal witness Fetter, a consultant of DEP, testified mainly in response to the Public Staff's recommendation for an equitable 50/50 sharing of CCR compliance costs. Utilizing his past experience as a state utility commission chairman and head of the utility rating practice at Fitch, Inc., he discussed how the adoption of such a recommendation would be inappropriate and viewed negatively by the credit rating agencies and investors. Tr. vol. 26, 74.

Witness Fetter testified that DEP corporate issuer credit ratings span between the middle level (A2, Stable outlook at Moody's) and the lowest level (A-, Stable outlook at S&P) of the "A" category. He testified that a regulated utility should endeavor to hold no lower than Baa1 (Moody's) to BBB+ (S&P), with a longer-term goal of moving into or maintaining the A category. *Id*. at 51.

Witness Fetter testified that the most qualitative factors used by rating agencies are regulation, management, and business strategy, along with access to energy, gas, and fuel supply with timely recovery of associated costs. He testified that credit rating agencies look for the consistent application of sound economic and regulatory principles by utility regulators. *Id*. at 53-54.

Witness Fetter testified that the financial community's view of the Commission has been relatively positive. He testified that Regulatory Research Associates (RRA) currently rates the North Carolina regulatory environment, which goes beyond the Commission to also include legislative and executive branch policies, as Average 1, among the top one-third of the 53 regulatory jurisdictions currently rated by RRA. He testified that RRA's view of North Carolina's regulation as overall relatively constructive from an investor viewpoint serves as a positive factor in the credit rating analytical process *Id*. at 58-59.

Witness Fetter testified that Moody's cautions that a DEP credit downgrade could occur if there is a decline in the credit supportiveness of DEP's regulatory relationships, particularly with regards to coal ash remediation recovery in North Carolina. *Id. at* 59. He stated that the Public Staff's sharing recommendation undercuts both the quantitative and qualitative factors that are positives in the credit rating agencies' assessment of DEP's ratings. The equitable 50/50 sharing proposal, in his opinion, is inconsistent with the core regulatory principle that prudently incurred costs should be allowed for recovery in customer rates. He testified that principle is fundamental to the regulatory compact that undergirds investor willingness to provide needed funding to public utilities, in exchange for a fair return or investment. Based upon his background, he believes that a stark movement away from traditional ratemaking principals, which would also be a clear break away from past Commission precedent, would shake the perception of investors and increase the costs of both equity and debt capital, an impact that ultimately lands at the doorstep of the customer. Accordingly, he recommended that the Company should seek to achieve excellent operating performance going forward and that the Commission should sustain the ongoing constructive regulatory environment, which together should maintain the Company's credit ratings no lower than their current levels within the "A" category. *Id. at* 74-75.

Discussion and Conclusions

The Commission notes that the parties submitted a considerable amount of testimony explaining credit metrics, quality, and ratings. The Company, in particular, shared its views on the potential impact of the Commission's decisions on several issues in this proceeding regarding possible future credit ratings changes and investor perceptions. The Commission found such testimony to be informative and appreciates the efforts of the parties in this regard.

The Commission recognizes and acknowledges that its decisions on important issues in general rate cases are part of the regulatory climate of a public utility operating within North Carolina and are critically reviewed by credit rating agencies. So too are the statutory framework and appellate court decisions. Ultimately, utility management is responsible for managing credit metrics and ratings and investor perceptions. It is they who have levers, such as timing and selection of future capital project spending, issuances of securities and dividend policy, managing daily operations efficiently, and even the provision of a convincing evidentiary record when prudency issues are raised in a proceeding such as this one.

North Carolina General Statutes Section 62-133 sets forth the factors to be considered by the Commission in setting rates for public utilities, stating:

> In fixing rates for any public utility subject to the provisions of this Chapter, . . . the Commission shall fix such rates as shall be fair to both the public utilities and to the consumer.

N.C.G.S. § 62-133(a). The statute further provides that "[t]he Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." N.C.G.S. § 62-133(d).

The statute does not require that the Commission consider the utility's credit ratings or stock prices when fixing rates, a fact that was conceded by DEP witnesses. However, the Commission must set rates that are reasonable and fair to both its customers and existing investors and should allow the utility to compete in the capital markets on reasonable terms.

The Commission has decided the issues in this proceeding based upon the requirements of N.C.G.S. § 62-133. The Commission has given the evidence on credit metrics due consideration. The rates fixed by this Order are supported by the greater weight of the evidence, are fair to both the public utilities and customers, produce just and reasonable rates, and should allow the utility, through prudent management, to access the capital markets on reasonable terms. Indeed, as to the last point the Commission views the ROE and capital structure approved herein to be investor and credit supportive.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

Cost of Service Adjustments

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations; the testimony and exhibits of DEP witnesses Smith, Metzler, Angers, Hatcher, Henderson, and Pirro, and Public Staff witnesses Dorgan, Metz, Saillor, and Maness; and the entire record in this proceeding.

Summary of the Evidence

As previously discussed, DEP and the Public Staff reached partial settlements with respect to some of the revenue requirement issues presented by the Company's Application, including those arising from the supplemental and rebuttal testimonies and exhibits. Section III of the First Partial Stipulation outlines a number of accounting adjustments to which DEP and the Public Staff have agreed, as does Section III.J through III.L of the Second Partial Stipulation. The revenue requirement effects of the agreed-upon issues are set out in detail in Smith Partial Settlement Ex. 3, Smith Second Settlement Ex. 3, Maness Stipulation Ex. 1, Schedule 1, and Maness Second Stipulation Ex. 1, Schedule 1 (the Partial Stipulation Revenue Requirement Exhibits). The accounting adjustments that are not specifically addressed in other findings and conclusions are discussed in more detail below.

Executive Compensation and Incentive Compensation

In its Application the Company removed 50% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEP in the test period. Witness Smith explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DEP has for purposes of this case made an adjustment to this item. Tr. vol. 13, 140.

Public Staff witness Dorgan recommended an additional adjustment to remove 50% of the benefits associated with these top five Duke Energy executives. Tr. vol. 15, 741. He contended that this adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers and that Public Staff believes that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests. *Id*. at 742. Witness Dorgan also recommended disallowance of incentive compensation related to earnings per share (EPS) and total shareholder return (TSR). *Id.* at 744-45. He asserted that incentive compensation tied to EPS and TSR metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. *Id.*

On rebuttal Company witness Metzler testified that the Public Staff's proposed adjustments are inappropriate and should be rejected by the Commission for a number of reasons. Tr. vol. 11, 106, 113-14. Witness Metzler also pointed out that no witness challenged the reasonableness of the level of compensation expenses reflected in the ratemaking test period for the Company. *Id.*

As part of the First Partial Stipulation "[t]he Company accept[ed] the Public Staff's proposed adjustment to executive compensation to remove 50 percent of the benefits associated with the five Duke Energy executives with the highest amounts of compensation, in addition to the 50 percent of their compensation removed in the Company's initial Application." First Partial Stipulation, § III.7. DEP also agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in Section III.10 of the First Partial Stipulation, which provides that the Company's employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of Company leadership.

Aviation Expenses

In its initial filing the Company removed 50% of the corporate aviation costs to account for flights that may not be related to provision of electric service. Tr. vol. 13, 144.

The Public Staff made a further adjustment after investigating the aviation expenses charged to DEP during the test year. Tr. vol. 15, 745. Public Staff witness Dorgan contended that based on his review of the flight logs, some of the flights appeared to be unrelated to the provision of utility services. *Id.* at 745-46. He also removed the DEP allocated portion of commercial international flights due to the Public Staff's determination that those flights were unrelated to the provision of utility service. *Id.* at 746.

On rebuttal Company witness Smith explained that all of the costs of the corporate aircraft have been allocated in accordance with the Company's cost allocation manual and that the Company's proposal to remove 50% of the costs is consistent with the Commission's order in Sub 1142. Tr. vol. 13, 190. She also pointed out that the Public Staff's recommendation would result in recovery of only 10% of corporate aviation costs. *Id.*

As part of the First Partial Stipulation the Company agreed to an adjustment that removes aviation expenses associated with international flights, in addition to the 50% of the Company's corporate aviation O&M expense removed in the Company's initial Application. First Partial Stipulation, § III.9.

Sponsorships and Donations

Public Staff witness Dorgan adjusted the Company's O&M Expenses to remove amounts paid to the chambers of commerce, and other donations, reasoning that they should be disallowed because they do not represent actual costs of providing electric service. Tr. vol. 15, 752.

In rebuttal Company witness Angers testified that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEP's service territory. Tr. vol. 11, 208. She explained that funds paid to Chambers of Commerce that are not specified as a donation or lobbying on the Chamber invoice are supporting business or economic development and are considered to be properly charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers. *Id*.

As part of the First Partial Stipulation the Company agreed to accept the Public Staff's position on sponsorships and donations expense, which removed certain expenses related to the chambers of commerce and donations. First Partial Stipulation, § III.11.

Outside Services

The Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEP by DEBS as well as those incurred by DEP directly and found certain expenses related to legal and non-legal invoices, which the Public Staff contended should not be charged to ratepayers. Tr. vol. 15, 746.

In rebuttal DEP witness Smith partially agreed with the items identified by the Public Staff related to certain outside services. Tr. vol. 13, 186. She agreed that certain outside services should be excluded; however, the Company maintains those costs have already been removed from the revenue requirement as mischarges due to human error. *Id*. at 186-87. She explained in her supplemental direct testimony that the Company proactively removed $0.2 million of system electric operating expenses from allocation to North Carolina retail electric expenses to cover any mischarges identified during the course of the rate case proceeding. *Id.* at 187. As such, the Company believes no additional adjustment to the proposed revenue increase is required for these costs. In addition, she stated that the Company disagrees with the Public Staff's removal of outside services charges of $42,000 for missing invoices explaining that the support for those charges, including invoices, was provided in response to Public Staff Data Request 105. She testified that it is the Company's understanding that the Public Staff agrees that this adjustment was an error. *Id.* She further testified that the Company also disagrees with the description on Line 1 of Dorgan Exhibit and Supplemental Exhibit 1 Schedule 3-1(k), "Remove items related to coal ash litigation." *Id.* Witness Smith explained that the costs that comprise this line item do not include items related to coal ash litigation.

As part of the First Partial Stipulation DEP and the Public Staff agreed that certain outside services expenses should be excluded. First Partial Stipulation, § III.11.

Rate Case Expenses

In its Application the Company requested to amortize the incremental rate case costs incurred for this docket over a five-year period. Tr. vol. 13, 144.

The Public Staff adjusted rate case expense to remove the unamortized portion of rate case expense in rate base, reasoning that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on a historical average of the number of years between rate case filings. Tr. vol. 15, 751-52. Public Staff witness Dorgan testified that the Public Staff takes the position that rate case expense does not rise to the level of being extraordinary in nature, and, therefore, does not require rate base treatment. *Id*.

In rebuttal witness Smith testified that the Company opposed the Public Staff's adjustment arguing that if the Public Staff had used the historical average costs and number of years between rate case filings since 2013, the amortization amount would have been $1.1 million, which is higher than the Company's proposed amortization amount. Tr. vol. 13, 191. Because the costs are known and measurable, the Company argues that inclusion of the costs in rate base is appropriate and that rate case expenses are incremental costs that have been incurred and funded by investors prior to new rates becoming effective. *Id*.

As part of the First Partial Stipulation DEP and the Public Staff agreed to amortize the rate case expenses over a five-year period but that the unamortized balance will not be included in rate base. First Partial Stipulation, § III.8.

Severance Costs

The Company made an adjustment to remove atypical severance and retention costs included in the test period and also requested to establish a regulatory asset to defer the North Carolina retail amount of $34.9 million of severance costs beginning when rates go in effect, to be amortized over a three-year period. Tr. vol. 15, 752; Application at 16.

Public Staff witness Dorgan adjusted the severance costs to reflect a normalized level over a five-year period, consistent with how the Public Staff has treated severance program costs in other utility rate cases. *Id.* at 752-53.

In rebuttal the Company opposed the Public Staff's adjustment arguing that the adjustment only changed the proposed amortization period and did not calculate a normalized five-year level of severance expense, which would have been greater than the Company's proposed amortization amount. Tr. vol. 13, 192-93.

As part of the First Partial Stipulation DEP and the Public Staff agreed that the severance expenses should be amortized over a three-year period but that the unamortized balance will not be included in rate base. First Partial Stipulation, § III.12.

Lobbying Expenses

Public Staff witness Dorgan noted that the Company assigned some lobbying expenses from the test year to below-the-line accounts, and therefore those costs were not included in the cost of service. Tr. vol. 15, 746. He further adjusted O&M expenses to remove what he characterized as additional lobbying costs, including O&M expenses that he believed were associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. *Id*. at 746-47.

In rebuttal DEP witness Angers explained why the Company opposed this adjustment and disagreed with witness Dorgan's characterization of these expenses. Tr. vol. 11, 201-02. Witness Angers testified that the Company's lobbying expenses are below-the-line, and thus not included in rates. Witness Angers further testified that the amounts the Company has booked above the line align with an independent study performed by KPMG. *Id.* at 202-05.

Witness Angers also testified that it appeared that the Public Staff also removed a percentage of above-the-line expenses related to dues paid to Edison Electric Institute (EEI). *Id.* at 205. Witness Dorgan did not address this adjustment in his testimony, but the Company was able to confirm the adjustment through discovery. *Id.* at 205-06. Witness Angers explained that the Company already books any costs for EEI that are related to lobbying, political activities, or contributions to a charitable foundation, below the line. She further stated that EEI provides a Schedule of Expenses that details EEI's budgeted spend for lobbying and the Company uses that schedule to record the portion of the payment related to lobbying below-the-line. Thus, the Company believes the Public Staff made this adjustment in error. *Id*. However, if the adjustment was not a mistake, witness Angers testified that the Public Staff offered no explanation in testimony to exclude additional amounts over and above-those the Company has already recorded below-the-line. *Id.* The Public Staff acknowledged that the adjustment related to EEI dues was made in error, and the Company accepted the Public Staff adjustment to lobbying expenses, as adjusted and corrected in Smith Partial Settlement Exhibit 3.

As part of the First Partial Stipulation the Company agreed to accept the Public Staff's recommended adjustments to remove certain expenses, as adjusted and corrected, in Smith Partial Settlement Exhibit 3. First Partial Stipulation, § III.13.

Board of Director Expenses

Witness Dorgan made an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that have been allocated to DEP. Tr. vol. 15, 743. He argued similarly to the adjustment the Public Staff made related to executive compensation, in that the Board of Directors has a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. *Id*. Accordingly, the Public Staff believed it was appropriate for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating the Board of Directors, as well as the cost of insurance for these individuals.

Witness Metzler explained that the Company is required to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. Tr. vol. 11, 116. She argued that it is not fair or reasonable to penalize the Company for being an investor-owned utility with attendant requirements to that corporate structure. *Id.*

As part of the First Partial Stipulation the Company agreed to accept the Public Staff's recommended adjustments to the Board of Directors' expenses. First Partial Stipulation, § III.13.

W. Asheville Vanderbilt 115kV Project

The Company recorded the Vanderbilt – W. Asheville 115kV transmission line project in the cost of service as a distribution project. Tr. vol. 15, 735. Public Staff witness Metz explained that the project involved reconductoring approximately two miles of the existing Vanderbilt to West Asheville 115 kV transmission line to accommodate power flows associated with generation additions in the Asheville area. *Id*. at 851. During the course of his review witness Metz discovered the Company had inadvertently booked this project to distribution plant rather than transmission plant; therefore, he believed the Company should reclassify and reallocate the costs accordingly. *Id.* Public Staff witness Dorgan thus made an adjustment to reflect a change in the allocation percentage to North Carolina retail to reflect that this project should have been recorded as transmission plant and not distribution plant.

In rebuttal DEP witness Smith testified that the Company opposes this adjustment because the Company had already made an adjustment in post-test year additions for this project in Smith Supplemental Exhibit 1. Tr. vol. 13, 194.

As part of the First Partial Stipulation the Company and Public Staff agreed to the adjustment to the W. Asheville Vanderbilt 115 kV project as reflected in Maness Stipulation Exhibit 1 and Smith Partial Settlement Exhibit 1 (subject to then unsettled jurisdictional and class allocation factor methodology differences). First Partial Stipulation, § III.14. The First Partial Stipulation also provided that the Company appropriately classified the line as transmission in its supplemental filing.

Credit Card Fees

In its Application DEP requested approval of a fee-free payment program for credit, debit, and ACH payment methods used by the Company's residential customers to pay their electric bills. Currently, customers are required to pay a $1.50 convenience fee, collected by a third-party vendor, for payments made by a credit card. Tr. vol. 11, 863. To offer this program, the Company proposes to pay these costs on behalf of its residential customers and recover these costs as part of its cost of service. *Id*. at 866. Company witness Smith described the Company's proposal to adjust its O&M expense for credit card fee expenses and, in her supplemental testimony, made an adjustment to reflect actual numbers of credit card transactions through February 2020. Tr. vol. 13, 146, 175.

Company witness Hatcher also testified to the value and need for the customer-driven program. Tr. vol. 11, 863-66. He explained that the requirement to pay a convenience fee when making a payment is one of the largest frustrations the Company's residential customers experience. *Id.* at 862. He stated that the Company's Customer Service department routinely receives inquiries about no-cost electronic payment options as evidenced by the Company's monthly residential transaction surveys. *Id.* at 864-65. According to witness Hatcher, customers have grown accustomed to paying for other products and services with a credit card or debit card without a separate, additional fee. *Id.* at 865. As such, many utility companies are now offering fee-free payment programs for their residential customers for all methods of payment. *Id*. at 863. Accordingly, witness Hatcher believes DEP residential customers should similarly benefit. *Id.* at 863. Duke Energy has seen 14% average year-over-year growth in credit/debit transactions over the past several years, and with this change the Company expects the growth rate to double – to 28% more transactions in 2019 than in 2018. *Id.* at 863-64.

While no party contested the value or benefits of the fee-free credit card program for residential customers, Public Staff witness Dorgan noted that the Company did not calculate any impacts to late payments or uncollectibles associated with the request to include credit card fees and has not removed the expenses related to the forms of payment that were utilized in the 2018 cost of service. Tr. vol. 15, 748. Therefore, the Public Staff made an adjustment to remove the O&M expenses included in the cost of service for 2018 associated with the increase in credit card transactions from the 2018 to 2019 period, to avoid double-counting costs associated with the same payments. *Id.*

In rebuttal witness Smith testified that the Company partially agreed with the Public Staff's adjustment and accepted the concept of the Public Staff's adjustment to remove O&M expense associated with the increase in fee-free program transactions from 2018 to 2019. Tr. vol. 13, 186. However, witness Smith testified that the Company has updated the calculation to reflect avoided transaction costs related to payment by check as reflected in Smith Rebuttal Ex. 1. *Id*.

As part of the First Partial Stipulation the Public Staff agreed to the Company's rebuttal position on credit card fees. First Partial Stipulation, § III.15.

End of Life Nuclear Materials & Supplies

Public Staff witness Metz testified that he reviewed the Company's Materials & Supplies (M&S) inventory. Based on that review, he recommended disallowance of $8.9 million in repair hold (RH) and quality assurance hold (QH) costs associated with inventory that has been in a hold status for four years or greater. Witness Metz stated that if inventory and its associated cost cannot be used for extended time periods, those parts (inventory) are unavailable for use, and ratepayers should not be burdened with those costs. Tr. vol. 15, 841-44. Witness Metz also proposed a positive salvage value of 10% be assigned to the M&S inventory, as opposed to the 0% value proposed by DEP. *Id.* at 847-49. Public Staff witness Dorgan made a corresponding adjustment to reflect the recommendation to remove certain items from inventory, as well as the application of a 10% salvage value to end-of-life (EOL) inventory. *Id.* at 748.

In rebuttal Company witness Henderson testified that DEP did not agree with the proposed adjustment regarding RH and QH M&S inventory. Witness Henderson explained that it is appropriate to include RH and QH items that are four or more years old in nuclear M&S inventory because such items ultimately benefit customers by ensuring adequate spare parts and material are available to support the safe and efficient operation of the plants. Tr. vol. 11, 146-47. Witness Henderson explained further that the Company balances priority and cost in order to maximize safety and reliable operation. *Id.* at 148. Witness Henderson described the Company's work to comply with the Commission's directive in the Sub 1142 Order to conform DEP's practices and procedures for managing nuclear and non-nuclear M&S to DEC's current practices and procedures to ensure that proper levels of inventory are maintained. *Id.* at 150. Regarding witness Metz's recommendation regarding EOL nuclear reserve, witness Henderson testified that, while DEP generally agrees that there will be some small amount of salvage value for nuclear M&S inventory at its end of life, this value will be offset because the Company had not applied inflation rates to the inventory values presented. Thus, DEP believed that current inventory value is a reasonable approximate of EOL value less any salvage amounts. *Id*. at 151.

As part of the First Partial Stipulation the Company accepted the Public Staff's adjustment to end-of-life nuclear M&S reserve expense, reduced as described in the direct testimony of Public Staff witness Metz. First Partial Stipulation, § III.16. Company witness Smith and Public Staff witness Maness supported this provision in their settlement supporting testimony. Tr. vol. 13, 231; tr. vol. 16, 29.

CertainTEED Payment Obligations

In the Application the Company included a conditional request for recovery of payment obligations related to a settlement agreement with CertainTEED Gypsum NC, Inc. (CertainTEED). Tr. vol. 13, 149. Recovery of these same expenses were also at issue in the Company's fuel and fuel-related charge adjustment proceeding in Docket No. E-2, Sub 1204 (Sub 1204), pending a determination of whether the costs are considered fuel costs under North Carolina law, such that they are recoverable through the fuel clause. The Company's Pro forma Adjustment No. 33 "Adjust for CertainTEED payment obligation" thus served as a placeholder in the event the Commission determined that the CertainTEED expenses were not eligible for recovery through the fuel clause. *Id*.

On November 25, 2019, the Commission issued its Order Approving Interim Fuel Clause Adjustment, Requiring Further Testimony, and Scheduling Hearing in Sub 1204, finding that the Company's payments to CertainTEED could be recovered as fuel-related costs pursuant to N.C.G.S. § 62-133.2(a1)(9) in the event that the Company's decisions and actions in connection with the settlement agreement were found to be reasonable and prudent. Tr. vol. 13, 176. Accordingly, on December 5, 2019, the Company filed a Letter Regarding Removal of CertainTEED Costs, indicating to the Commission its intent to remove the CertainTEED costs from its base rate request through its supplemental filing, which it subsequently made on March 13, 2020.

The Public Staff requested that the Commission remove the CertainTEED payment obligation from the Company's rate base but later agreed to withdraw this recommended adjustment because the Company had already removed the expense from this proceeding in its supplemental filing. Tr. vol. 15, 751; First Partial Stipulation, § III.19. The Public Staff and the Company therefore agreed that the CertainTEED Payment Obligation was appropriately removed from this proceeding.

May 2020 Updates

On July 2, 2020, the Company filed second supplemental direct testimony and exhibits updating certain material pro forma adjustments through May 31, 2020 (May 2020 Updates). The Company updated revenue requirements through May 2020 for the following pro forma adjustments: customer growth; post-test year additions to plant in service; accumulated depreciation; depreciation expense; property taxes; O&M non-labor expenses; O&M labor expenses; merger related costs; interest synchronization; cash working capital; and an adjustment to update and remove storm costs for securitization. Tr. vol. 13, 240-42.

Though the May 2020 Updates were initially opposed by the Public Staff, DEP and the Public Staff reached agreement regarding the May 2020 Updates in the Second Partial Stipulation, agreeing to include the adjustments, pending and subject to the Public Staff's audit of the updates. Second Partial Stipulation, §§ III.J., IV.A. DEP and the Public Staff also agreed to include updates for benefits and executive compensation. Second Partial Stipulation, § III.J. Finally, DEP and the Public Staff agreed to limit the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's February 2020 update to recognize the uncertainty regarding the effects of COVID-19, with the 75% limitation applicable only if the net effect of the updates on revenues is a revenue requirement increase. *Id.*

After completing the aforementioned audit, on September 16, 2020, Public Staff witness Maness filed second supplemental and settlement testimony and exhibits updating and revising the Public Staff's calculation of its recommended revenue requirement, including the impacts of the Second Partial Stipulation and the accompanying review of the Company's May 2020 Updates. The Public Staff reviewed the Company's proposed updates to net plant, depreciation expense and accumulated depreciation, new depreciation rates, and revenues and related expenses (weather, and customer growth and usage). The Public Staff recommended certain adjustments to these items, and also recommended an adjustment to update certain employee benefits, the Asheville production displacement adjustment, O&M non-labor expense (inflation), and cash working capital, which are reflected in Maness Second Stipulation Ex. 1. Tr. vol. 16, 43-44. The adjustments to the revenue requirement for those items previously settled between the Company and the Public Staff (benefits, weather, customer growth and usage, Asheville production displacement, and inflation) totaled ($318,000), exclusive of the impact on cash working capital.

Lead-Lag Study

The Company submitted a new Lead-Lag Study as Angers Exhibit 3. DEP subsequently revised Angers Exhibit 3 as part of the supplemental testimony of witness Angers. In her direct testimony, Public Staff witness Dorgan proposed adjustments to cash working capital based on the Public Staff's review of the Lead-Lag Study. Witness Angers testified that the Company agreed with the Public Staff's adjustments to cash working capital and noted that the adjustments are consistent with the changes described in the supplemental testimony that is included in the revised Lead-Lag Study.

Weather Normalization, Customer Growth and Usage

DEP witness Pirro testified that he provided the retail sales and number of customers to DEP witness Smith for use in calculating the pro forma adjustment to growth in customers. Tr. vol. 11, 1082. He explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the test period, the Company used a combination of regression analysis and a customer-by-customer approach. *Id.* at 1083-84. In his supplemental testimony, witness Pirro testified that the Company had proactively modified its adjustments to annual revenues for customer growth, change in usage, and weather normalization based on Public Staff witness Saillor's recommended modifications in the DEC Rate Case in Docket No. E-7, Sub 1214, which the Company agreed with in principle. *Id*. at 1116-17.

As to customer growth and change in usage, those modifications included:

- Modifying DEP's customer-by-customer approach for openings in the test period by determining average monthly usage through taking the average of the 12 months of billing data following initial month of service;

- Modifying DEP's customer-by-customer approach for openings in the extended period (through February 29, 2020) by removing the initial month of service from the average usage calculation;

- Removing the Basic Customer Charge (BCC) revenues from the change in usage calculations;

- The removal of the change in usage revenue adjustment for the lighting rate class; and

- The inclusion of a change in usage adjustment for the general and industrial rate classes.

Regarding weather normalization, those modifications included: the removal of BCC revenues from the calculations of average customer class rates; and summing of the monthly NC retail kWh weather adjustments within the test period for each customer class in place of multiplying the test period system retail kWh weather adjustment times the annual NC retail-to-system sales ratio. *Id.* at 1117.

Public Staff witness Saillor testified similarly. Tr. vol. 15, 701-03. He also proposed two modifications to the end of test period methodology proposed by DEP: (1) summing the 12 months of billing data following the initial month of service and dividing by 12; and (2) replacing actual sales with weather-normalized sales in the adjustments for the SGS rate class. *Id.* at 708. He also explained his proposed modifications to the customer growth and change in usage adjustments and testified that the Company agrees with each modification except for the change to weather-normalized sales for the SGS rate classes, which was not addressed in witness Pirro's supplemental direct testimony. *Id*. at 709-10.

In rebuttal witness Pirro testified that the Company agreed with the formulaic changes suggested by witness Saillor. In addition, the Company inadvertently did not address witness Saillor's calculation methodology to weather normalize sales for the SGS rate class, with which the Company also agreed. Tr. vol. 11, 1125-26. However, the Company disagreed with witness Saillor's use of customer growth projections through February 2020 because of the significant reduction in its load and associated revenues experienced during the COVID-19 emergency, some of which, the Company believes, could become permanent. *Id.* at 1126. Thus, the Company asserted that reflecting these changes closer in time to the hearing would result in a more accurate depiction of the Company's load forecast. Witness Pirro also testified that there appeared to be a spreadsheet issue with the change in number of bills displayed in witness Dorgan's Supplemental Exhibit 1, Schedule 3-1(b) compared to the change in number of bills displayed in Saillor Supplemental Ex. 3. *Id*. at 1127. He testified that he understood that the Public Staff agreed that the number of bills displayed on Line 15 in Dorgan Supplemental Ex. 1, Schedule 3-1(b) should be 473,731, consistent with Saillor Supplemental Ex. 3.

In his second supplemental direct testimony, witness Pirro testified that the Company updated its customer growth adjustment through May 31, 2020, to incorporate certain known and measurable changes. Tr. vol. 11, 1143. He explained that the updated customer growth adjustment reflects a significant reduction in the Company's load and associated revenues as a result of many commercial and industrial customers as well as schools and colleges scaling back operations, as well as an increase in residential usage, during the COVID-19 pandemic. *Id.* at 1144. Witness Pirro's updated customer growth adjustment reflects the reduction in nonresidential load and increase in residential usage through May 31, 2020.

As noted above, the Second Partial Stipulation addressed the consideration of the May 2020 Updates, with the parties agreeing to include the adjustments, pending and subject to the Public Staff's audit of the updates, and also subject to a limit of the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's February 2020 update to recognize the uncertainty regarding the effects of COVID-19 if the net effect of the updates on revenues is a revenue requirement increase. Witness

Pirro filed Pirro Second Settlement Ex. 4 to reflect the revised revenue requirement resulting from the Second Partial Stipulation and the Company's position on unsettled items.

Non-Labor O&M

The Company adjusted annual non-labor, non-fuel O&M costs, to reflect the increase in costs during the test year that occurred due to the effect of inflation as of December 31, 2018. Tr. vol. 15, 730. Public Staff witness Dorgan adjusted the Company's inflation adjustment to reflect the inflation factor through December, 31, 2019, and modified the Company's inflation adjustment to reflect the Public Staff's adjustment to include variable O&M expenses for changes in customer growth and the removal of aviation expenses, Board of Directors expenses, outside services expenses, uncollectibles, sponsorships and donations, and advertising. *Id.* at 740-41. In rebuttal Company witness Smith did not oppose the adjustment. Subsequently, in the May 2020 Updates, the Public Staff adjusted the amount of non-labor O&M expense included in the determination of the base to which the inflation rate is applied to include the Public Staff's recommended adjustment in non-fuel variable O&M expenses due to customer growth. The Company noted that it agreed with this adjustment. Tr. vol. 16, 49. The specific updated Public Staff adjustments discussed in witness Maness's testimony to which the Company agreed are as follows:

Plant in Service and Accumulated Depreciation

Public Staff witness Maness updated net plant for known and actual changes to depreciation expense and non-generation plant retirements recorded between the end of the test year and May 31, 2020. Tr. vol. 16, 46. Witness Maness also included adjustments recommended by Public Staff witness Metz removing costs related to the Company's Project Focal Point. *Id.* The impact of the removal of costs associated with Project Focal Point, which was part of the Public Staff's adjustments to the update of plant, depreciation expense, and accumulated depreciation, are included in the unsettled update to plant and accumulated depreciation as of May 31, 2020, listed on Schedule 1, Line 5 of Maness Second Stipulation Ex. 1. Although the Public Staff and the Company agreed the item should be removed from plant in service and accumulated depreciation, the item remains unsettled until the Commission determines the appropriate depreciation rates, which are included in the calculation of the adjustment. The Company agreed that these adjustments should be included in the calculation of the final revenue requirement determined in the present case.

Updated Revenues

Public Staff witness Maness updated the energy-related non-fuel variable O&M expense per kWh rate and the annual customer-related variable O&M expense per kWh rate to reflect the use of the SCP allocation methodology to calculate expense amounts used in the calculations and corrected a Public Staff formula error in the schedule. Tr. vol. 16, 47. Witness Maness also updated the customer growth and usage amounts per the recommendation of Public Staff witness Saillor. *Id.* at 47-48. The Company agreed with this adjustment.

Benefits

Public Staff witness Maness updated the benefits related to other post-employment benefits, pension, FASB 112, and non-qualified pensions to reflect the updated 2020 actuarial amounts that became available after the initial update period. The Company agreed with this adjustment. *Id.*

Nuclear Decommissioning Trust Fund

Public Staff witness Hinton testified that in this case DEP proposes a total Nuclear Decommissioning Trust Fund (NDTF) expense of approximately $19.6 million, the same level included in Sub 1142. Tr. vol. 15, 334. He explained that the $19.6 million approved decommissioning expense was based on the Company's 2015 Nuclear Decommissioning Studies. *Id*. He further explained that the Company filed a Nuclear Decommissioning Cost and Funding Report in 2015, which the Company made several updates and adjustments in Sub 1142. *Id*. at 336.

Witness Hinton testified that the Public Staff has concerns with the current use of a cost estimate filed in 2015, based on dollars from 2014. *Id*. at 336-37. DEP's Decommissioning Cost Analyses filed on March 12, 2020, in Docket No. E-100, Sub 56, estimated the cost to decommission DEP's four nuclear units as approximately 18% higher than estimated in the 2015 Cost Analyses. *Id*. Thus, the Public Staff recommends basing the decommissioning expense in this rate case on the 2020 Cost Analyses. *Id*. Witness Hinton testified that he found the Company's assumptions for calculating the Decommissioning expense to be reasonable, with the exception of DEP's proposed rates of return for its qualified trust fund (4.56% average projected long-run rate of return for DEP's qualified trust funds), which he testified "are unreasonable and overly conservative." *Id*. at 340. Relying on witness Woolridge's CAPM testimony regarding a reasonable expected rate of return for the Company's cost of equity, witness Hinton testified that he believes a 9.00% to 9.50% expected rate of return for these assets is reasonable. *Id*. He also provided Confidential Ex. 6, which showed the historical annual rates of return on the funds and testified that DEP's long-run rate of return of 4.56% is overly conservative based on his review of past performance after taxes and fees. He noted that the historical rates of return shown in Exhibit 6 reflected three recessionary periods that were followed by periods of positive growth in the value of DEP's qualified funds. *Id*. at 341. In addition, he argued that the Company's pension and decommissioning funds have similar asset allocations and annual earned rates of return but use a different overall rate of return on its overall fund investments. *Id*. at 342. Finally, witness Hinton testified that he considered other sources, such as Dominion Energy North Carolina's (Dominion) current decommissioning funding study that reflects Dominion's projection of its rate of return on its qualified funds filed in Docket No. E-100, Sub 56. Based on these factors and analysis, witness Hinton recommended use of an overall expected 6.00% rate of return for DEP's qualified trust funds and that the Commission reduce the Company's decommissioning expense to $0. *Id*. at 345.

In rebuttal DEP witness Doss provided an overview of the Commission's Guidelines for determining and reporting nuclear decommissioning costs and the process for determining the amount of nuclear decommissioning costs included in the Company's revenue requirement. Tr. vol. 16, 346-53. He explained that when the Company's Application was filed on October 30, 2019, the Company opted to keep the revenue requirement relating to nuclear decommissioning expense the same as the amount approved in the 2018 Rate Case given that a new study was expected by the end of 2019, and the Company would be going through the lengthy process of updating the cost and funding model in 2020, which was not anticipated to be complete prior to the close of this rate case. *Id*. at 354.

In response to Public Staff witness Hinton's recommendation that the Commission update the Company's decommissioning expense outside of the typical process witness Doss explained that the process of developing a cost and funding model is complicated and includes many inputs and assumptions. *Id*. at 356. He testified that "[s]imply put, there is a reason the Commission requires the Company to go through the exercise of developing a cost and funding model and that the Commission allows 210 days from the receipt of costs estimates for the Company to complete the funding report." *Id*. Witness Doss explained "that process is currently underway and should not be allowed to be short-circuited by the Public Staff." *Id*. Regarding witness Hinton's comparison to market returns relating to ROE as a basis for his recommended NDTF return, DEP witness D'Ascendis testified that witness Hinton's recommendation incorrectly assumes there is no distinction between expected returns assumed in NDTF funding assumptions and other managed asset funds such as pension funds and the required returns that are the subject of his and witness Woolridge's testimony. Tr. vol. 11, 577. Witness D'Ascendis explained that the investor-required return on the market is not equivalent to the expected market return estimates used by asset fund managers, and that one cannot be substituted for the other. *Id*. at 578. He explained that investors may use a more conservative required return estimate for asset fund management purposes than the required return that applies to individual equity investments. *Id*. He also explained that asset fund managers are concerned with investing funds at an expected return to meet expected liabilities over a finite period, while individual equity investors decide whether to commit capital to a given security based on the return that they require to be compensated for the risks associated with that security, in perpetuity. *Id*. at 579. Further, witness D'Ascendis testified that the Commission has previously recognized the distinction between expected returns and required returns. *Id*. at 579-80.

As part of the Second Partial Stipulation DEP and the Public Staff agreed to reduce the annual funding for the Company's NDTF by $8.7 million, and further agreed to support this funding amount in DEP's current cost and funding decommissioning Docket No. E-100, Sub 56. To the extent the Commission orders in that docket a different level of funding than the amount the parties agreed to in the Second Partial Stipulation, the parties agreed that the Company will defer the difference in a regulatory asset or liability to be considered in the next rate case. Second Partial Stipulation, § III.K.

Deferred Non-ARO Environmental Costs

Public Staff witness Maness testified that pursuant to the Commission's approval of the 2016 request for deferral filed in Docket No. E-2, Sub 1103, the Company is proposing to defer and amortize certain depreciation and return requirements related to certain capital projects placed into plant in service since the most recent rate proceeding. Tr. vol. 15, 1583. He explained that these projects are not classified by the Company as legal obligations associated with the retirement of coal ash facilities or the generating plants with which those facilities are associated; instead, they are intended to address coal ash issues related to the continuing operation of the applicable generating plants. *Id.* Although they are not part of the legal obligation that gives rise to DEP's coal ash asset retirement obligation (ARO), the Company and Public Staff agree that these costs are eligible for deferral pursuant to the terms of the Sub 1103 deferral accounting request, because they are needed to fulfill the Company's responsibilities under North Carolina's Coal Ash Management Act (CAMA) and the United States Environmental Protection Agency's Coal Combustion Residuals Rule (CCR Rule). *Id*. However, witness Maness testified that although he does not oppose deferral of the capital (return and depreciation) costs of the projects in this case, he does not agree with the five-year period proposed by the Company over which to amortize the deferred costs. He instead recommended an amortization period of ten years, which would lower the revenue requirement and substantially ease the annual impact of the deferral and amortization on the ratepayer, and that the reduction would not directly harm the Company in that the unamortized amount would earn a return through being included in rate base. *Id.* at 1584.

In rebuttal DEP witness Smith testified that the Company does not agree with witness Maness's recommendation to increase the amortization period for non-ARO related deferred capital expenditures. Tr. vol. 13, 209. She explained that the Public Staff has recommended extending amortization periods proposed by the Company when the amortization involves amounts to be collected from customers but recommends shortening the periods when the amortization involves amounts to be refunded to customers. *Id*. She explained that the Company considered annual rate impacts in its recommendation of the five-year amortization and considered the Commission's decision in the 2018 Rate Case in arriving at its proposed amortization period. *Id*.

As part of the Second Partial Stipulation DEP and the Public Staff agreed that amortization of deferred non-ARO environmental costs over an eight-year period is appropriate. Second Partial Stipulation, § III.L.

Asheville Combined Cycle Project

On March 28, 2016, the Commission approved a certificate of public convenience and necessity (CPCN) for the Asheville Combined Cycle (CC) units (Asheville CC Project), finding that its construction was needed to meet the projected growth in the

Company's Western Region and to meet DEP's total system needs. *See* Order Granting Application in Part, with Conditions, and Denying Application in Part, *Application of Duke Energy Progress, LLC, for a Certificate of Public Convenience and Necessity to Construct a 752-MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville*, No. E-2, Sub 1089 (N.C.U.C. Mar. 28, 2016); Tr. vol. 11, 982.

At the time the Company filed its Application in this rate case the Asheville Steam Electric Generating Plant was anticipated to be retired in December 2019 with the new Asheville CC Project scheduled to be in service that same month. Company witness Turner testified that the Asheville CC Project comprises two 1x1 CC dual fuel units (power blocks), and that each power block contains a combustion turbine (CT) generator and steam turbine generator and has a capacity of 280 MW. Tr. vol. 11, 981.

As part of the Application the Company requested that the costs associated with the plant (depreciation, property taxes, incremental O&M and return) incurred from the time the facility is placed into service until the time the approved costs are to be reflected in the new rates, be deferred and amortized beginning with the effective date the Commission approves new rates in this proceeding. Application, at 19; Tr. vol. 13, 166. DEP witness Smith testified that without approval of the Company's request to defer the Asheville CC Project costs, the Company would face an earnings degradation of approximately 80 basis points. Tr. vol. 13, 166. She further explained that approval of the Company's accounting order request for the Asheville CC Project would be consistent with prior Commission practice regarding significant new generation plants and would better align costs with revenues. *Id.*

The Company made a pro forma adjustment to include the amortization of the deferred costs related to the Asheville CC Project that includes an annual level of amortization of deferred costs, including a return on investment, over a three-year period. Tr. vol. 15, 736. As part of this adjustment, DEP included a separate pro forma adjustment to include a proxy for the ongoing O&M expenses and M&S inventory for the Asheville CC Project. *Id*. The Company also included a pro forma adjustment to reflect Power Block 1, including the common plant, and a combustion turbine from Power Block 2 in plant additions as of December 31, 2019, which represented 480 MW of the 580 MW (nameplate capacity) Asheville CC facility that were placed in service as of December 31, 2019. *Id.*

In her supplemental testimony Company witness Smith testified that the Company had updated the Asheville CC deferred balance amortization to reflect the estimated deferred costs and associated regulatory asset established for the Asheville CC Project. Tr. vol. 13, 176-77. She explained that at the time of DEP's Application the plant was expected to be in service in late 2019 and, as of February 29, 2020, Units 5, 6, and 7 were placed in service with Unit 8 expected to be in service before the start of the evidentiary hearing, initially scheduled to commence on May 4, 2020. *Id*. at 177.

Public Staff witness Metz testified that three of the four units at DEP's Asheville CC Project had been placed in service and explained that the plant was only partially in service due to unexpected events that occurred during testing at one of the steam turbines, which required repairs and further testing. Tr. vol. 15, 823. Witness Metz encouraged DEP to continue negotiations with the original equipment manufacturer (OEM) to obtain a "no cost" extended warranty on at least the steam turbine and its associated generator that had experienced damage. *Id.* at 824-25. Additionally, he recommended the Commission require the Company to file a letter in this docket notifying the Commission when the Power Block 2 steam turbine was completed and available for full economic dispatch. Tr. vol. 15, 825-26. Witness Metz also proposed an adjustment to the Asheville CC Project to account for the time delay between the Company's request in this case and the time rates will actually go in effect and to establish an estimated amount of expected plant expenses. *Id.* at 849.

Witness Metz revised the Asheville CC Project O&M estimated expense to reflect a revised cost and change in the cost calculation methodology, both applying a weighted average (instead of simple average employed by DEP) of CC expense versus nameplate capacity and removing certain costs he found to be duplicative or incorrectly charged. *Id.* at 850-51. As a result, Public Staff witness Dorgan adjusted the annual O&M expenses utilized by the Company for the Asheville CC Project and testified that it was his understanding that the Company accepted the Public Staff's methodology for calculating a proxy for O&M expenses. *Id.* at 736-37. Further, witness Dorgan recommended that the deferred Asheville CC Project costs for North Carolina retail be recovered through a levelized amortization over a five-year period. *Id.* at 738. Witness Dorgan also explained that the Company made an adjustment to include 480 MW of the Asheville CC Project in service on December 31, 2019 and that, based on the Public Staff's understanding, the remaining 100 MW was placed in service on April 5, 2020 and would be addressed by the Company in a subsequent supplemental testimony filing. *Id*. at 737, 753-54. Finally, witness Dorgan testified that, with the net addition of kWh due to the Asheville CC Project, other DEP resources will operate less frequently or at lower levels of output and thus incur fewer non-fuel variable O&M expenses. *Id.* at 754. As such he reduced non-fuel variable O&M expenses in a displacement adjustment to prevent the inclusion in cost of service of more than the end-of-period level of these types of expenses.

NC WARN witness Powers testified the project cannot be considered used and useful because both phases were not online until April 5, 2020. *Id.* at 886.

In rebuttal and regarding witness Metz's recommendations DEP witness Turner noted that the repairs performed by the OEM restored the steam turbine generator component of Power Block 2 to new condition, and that the existing contract with the OEM provides for a two-year warranty on both power blocks. Tr. vol. 11, 984. Witness Turner stated that DEP's negotiations with the OEM regarding Power Block 2 are ongoing and include representatives from DEP's legal, supply chain, and project management organizations. *Id.* Regarding witness Metz's recommendation for a letter update, she testified that after completion of the repair to the Power Block 2 steam turbine, DEP submitted an update to the Commission in Docket No. E-2, Sub 1089, stating that the Power Block 2 steam turbine generator went into commercial operation on April 5, 2020. Witness Turner noted an exhibit to her rebuttal testimony, believing based on discussion with the Public Staff that DEP had satisfied the Public Staff's recommendation. *Id*. at 984-85.

Regarding the Public Staff's displacement adjustment for the Asheville CC Project, witness Turner testified that the adjustment is not warranted. She explained that the Asheville CC Project represents the addition of two new CC facilities to the DEP fleet that need to be operated and maintained. *Id*. at 983. In addition to meeting the Company's obligations under the Mountain Energy Act, she noted that these units will also serve a growing number of customers in the surrounding area and the associated growth of energy and peak demand requirements. *Id.*

In rebuttal Company witness Smith stated that DEP accepted the Public Staff's methodology for calculating annualized O&M for the Asheville CC Project but opposed the adjustment to use the annuity factor method to calculate amortization expense, removing the deferral and ADIT balances from the rate base, and disagreed with the dollar amount of the adjustment because it needed to be updated to include Unit 8, which went into service on April 5, 2020. *Id.* at 187, 193-94. In addition, she testified that DEP opposed the Public Staff's recommended amortization period of five years for the deferred costs. *Id.* at 194. Finally, she adjusted the deferred balance of the Asheville CC Project that went into service on April 5, 2020. *Id.* at 215.

In his supplemental testimony Public Staff witness Dorgan updated his adjustment to the Asheville CC Project to reflect DEP's actual costs as of February 2020, and incorporated adjustments to the levelization calculation to reflect that Power Block 2 came online on April 5, 2020, and the entire Asheville CC Project can be economically dispatched. Tr. vol. 15, 772.

The First Partial Stipulation settled the contested issues regarded the Project. Section III.17 of the First Partial Stipulation provided that the Asheville CC Project is complete, placed in service, and available for economic dispatch. It also provided that (a) the appropriate amortization period for the deferred expenses for the Asheville CC Project is four years with a levelized return; (b) the Company's non-fuel variable O&M expense related to the Asheville CC Project should be reduced to account for a production displacement adjustment; and (c) the amount of Asheville CC plant in service appropriate to include in rate base and used for the deferral calculation in this proceeding is the amount reflected in the Company's rebuttal testimony – subject to unsettled jurisdictional and class allocation factor methodology differences – and that the Public Staff reserves the right to review any actual reimbursements received from the EPC contractor in a subsequent rate case. Section III.20 provided to include annualized accumulated depreciation for the Asheville CC Project not previously included in supplemental or rebuttal filings.

In her settlement supporting testimony Company witness Smith explained that the Public Staff and DEP agreed to an adjustment to accumulated depreciation reserve related to the Asheville CC Project to correct an error in the Company's rebuttal filing. Tr. vol. 13, 232.

In his supplemental second settlement testimony Public Staff witness Maness stated that he updated the Asheville production displacement calculation as updated by the Company in its May 2020 update to reflect the calculation using the SCP allocation method, as agreed to by the parties in the Second Partial Stipulation. He stated that the Company had based the calculation on the SWPA allocation factors. Tr. vol. 16, 48.

NC WARN witness Powers testified that NC WARN did not support allowing DEP to recover costs related to the construction of its Asheville CC Project. NC WARN argued that the Asheville CC Project was not reasonable and prudent nor the least cost mix of generation. Witness Powers testified that there were several example of the lower-cost regional power supply that could have been contracted as an alternative to an expensive buildout at Asheville. Witness Powers described additional alternatives in her testimony. Tr. vol. 15, 883-84. Witness Powers additionally described how DEP could have utilized battery storage to reduce costs. She testified that Duke Energy has spent approximately $820 million building the Asheville combined cycle power plant – resulting in DEP's request in this rate case to recover approximately $770 million – that could have been avoided by simply allowing existing solar facilities in North Carolina to add battery storage at their own expense in return for reasonable payment for the added value of the storage capacity. *Id.* at 885.

Discussion and Conclusions

Based on the foregoing and the entire record, the Commission concludes that the provisions of the Public Staff Partial Stipulations on cost-of-service adjustments aptly demonstrate the efforts of the stipulating parties to reach compromise on many details of DEP's operating costs. Auditing a public utility's accounting records and formulating a position on the many cost of service items is a labor intensive and tedious job. The Commission appreciates the work of the Public Staff and the stipulating parties for coming together and working out many of these accounting issues. The Commission determines that the cost adjustment provisions are the result of give-and-take negotiations, and therefore the Commission places great weight on the cost adjustment provisions of Public Staff stipulations. As a result, the Commission concludes that the stipulated adjustments discussed herein are just and reasonable, and the portions of the Public Staff First and Second Stipulations on cost-of-service adjustments should be approved.

Turning specifically to NC WARN's challenge to the cost recovery related to the construction of DEP's Asheville CC Project, the Commission notes that no NC WARN witness conducted any independent analysis, using the information available at the time the Company's investment decisions were made, to support any contention that DEP's Asheville CC Project was unreasonable or imprudent. The Commission instead credits the testimony of Company witnesses Turner and Smith, and Public Staff witnesses Metz, Dorgan, and Maness, as summarized above. That evidence supports that the Company made reasonable and prudent investment decisions with the information available at the time. Additionally, the Commission observes that it already addressed the need for this generation when it issued the CPCN for the Project on March 28, 2016. For these reasons, the Commission rejects NC WARN's recommendation to disallow recovery of the expenses associated with DEP's construction of the two 280 MW combined-cycle natural gas plants at the Asheville Combined Cycle Power Plant.

Accordingly, and in light of all the evidence presented, the Commission finds and concludes it to be just and reasonable that the Asheville CC Project is complete, placed in service, and available for economic dispatch; the appropriate amortization period for the deferred expenses for the Asheville CC Project is four years with a levelized return; the Company's non-fuel variable O&M expense related to the Asheville CC Project should be reduced to account for a production displacement adjustment; the amount of Asheville CC plant in service appropriate to include in rate base and used for the deferral calculation in this proceeding is the amount reflected in the Company's rebuttal testimony (as adjusted by Public Staff witness Maness in his supplemental second settlement testimony); the Public Staff reserves the right to review any actual reimbursements received from the EPC contractor in a subsequent rate case; and annualized accumulated depreciation for the Asheville CC Project not previously included in supplemental or rebuttal filings should be included.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-39

Deferral of Grid Improvement Plan Capital Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations entered into between DEP and several parties; the testimony and exhibits of DEP witnesses Smith, Young, and Oliver, Public Staff witnesses David Williamson, Tommy Williamson, Maness, Thomas, and McLawhorn, NCSEA/NCJC et al. witnesses Stephens and Alvarez, CIGFUR witness Phillips, CUCA witness O'Donnell, Harris Teeter witness Bieber, and Vote Solar witnesses Nostrand and Fitch; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

DEP witness Kim Smith explained that DEP requests an accounting order that would allow DEP to defer its GIP capital costs starting with costs incurred in January 2020. She referenced witness Oliver's testimony that DEP's GIP costs meet the Commission's test for deferral because they are not simple, regularly occurring, inconsequential investments but rather are major nonroutine investments that produce substantial customer benefits. She asserted that absent deferral, if DEP pursued its proposed GIP spending, the Company would experience a significant adverse earnings impact that would grow to more than 100 basis points by 2022.

DEP witness Steven Young testified that investors are looking for modernized mechanisms that allow more timely recovery of investments. He stated that "now most of our investments are smaller in nature. They go in service quicker." He also stated that the Company must absorb the related depreciation, O&M, and interest expense, and the deferral mechanism helps to address the lag in both cash and in earnings. Consolidated Tr. vol. 3, 49-50.

DEP witness Jay Oliver testified that DEP developed its GIP to respond to these seven “megatrends”:

(1) Population and business growth continue in North Carolina and is concentrated in urban and suburban areas.

(2) Distributed energy technology is advancing rapidly; there are new kinds of load and resources impacting the grid.

(3) New technologies offer new capabilities and functions for the grid.

(4) Customer expectations have changed.

(5) There are more environmental commitments at every level of government.

(6) Major weather events are more numerous and more severe.

(7) Physical and cyber threats to the grid are more sophisticated and are increasing.

Witness Oliver’s Exhibit 10 provided an overview of DEP’s GIP and showed that DEP seeks deferral accounting for the capital costs related to $987.8 million in capital spending on the following GIP programs during 2020 through 2022: (1) Self-Optimizing Grid; (2) Integrated Volt/VAR Control; (3) Transmission Hardening and Resiliency; (4) Targeted Undergrounding; (5) Distribution Transformer Retrofit; (6) Long Duration Interruptions/High Impact Sites; (7) Transmission Transformer Bank Replacement; (8) Oil Breaker Replacements; (9) Enterprise Communications; (10) Distribution Automation; (11) Transmission System Intelligence; (12) Enterprise Applications; (13) Integrated Systems and Operations Planning; (14) Distributed Energy Resource Dispatch Enterprise Tool; (15) Power Electronics for Volt/VAR Control; and (16) Physical and Cyber Security.

Public Staff Testimony

Public Staff witnesses David Williamson and Tommy Williamson (Williamsons) testified that DEP is currently working on thirteen of the GIP programs, that it had spent about $38 million on the programs during the 2018 test year on a system basis, and another $163.8 million in 2019, again on a system basis. In 2020, DEP spent another $36.9 million as of the end of February.

The Public Staff reviewed DEP’s proposed GIP in order to identify programs that it believes are unique and extraordinary and hence appropriate to consider for deferral. They sought to identify those programs that would bring the grid up to new standards of operation and reliability. The Public Staff rejected for deferral those programs that are the kinds of activities that DEP engages in or should engage in on a routine and continuous basis. The Williamsons concluded that the following GIP programs are extraordinary: (1) The automation and control portion of the Self-Optimizing Grid; (2) the advanced distribution management system portion of Self-Optimizing Grid; (3) Transmission System Intelligence; (4) the Underground Automation portion of Distribution Automation; and (5) Integrated Systems and Operations Planning. The Public Staff said these initiatives are transformative and would provide significant new capabilities to the grid.

Public Staff witness Michael Maness testified that DEP intends to spend about $186 million on the GIP programs that the Williamsons identified as extraordinary. Witness Maness stated that, absent deferral, the return on equity impact of these programs would average about 14 basis points over the next three years, and under normal circumstances the Public Staff would not recommend deferral of an investment with a basis point impact of such a small nature.[10] He stated that in this case, however, the Public Staff took notice of the Commission's order from DEC's last rate case, which was issued June 22, 2018, in Docket No. E-7, Sub 1146 (2018 DEC Rate Order). Witness Maness asserted that in the 2018 DEC Rate Order the Commission appeared willing to be lenient regarding the magnitude of costs or financial impacts necessary to justify deferral for grid improvement investments. For that reason, he did not object to the Commission allowing deferral of the capital costs of the five programs identified by the Williamsons, so long as the Commission determined that the estimated basis point impact falls within the range of leniency that the Commission is willing to grant. Witness Maness further stated that such a deferral should be considered specific to this case and not be treated as precedent in any future general rate case proceeding or deferral request.

Public Staff witness Thomas reviewed the cost-benefit analyses that DEP provided for some of the GIP programs. While he did not recommend rejection of any of the programs, he did express concern that a majority of the benefits identified in DEP's cost-benefit analyses were estimates of the financial benefits customers would receive by avoiding power outages. He noted that DEP relied on a Lawrence Berkeley National Laboratory report (LBNL Report) to estimate the financial value of these benefits. Witness Thomas testified that 87% of the benefits of DEP's GIP were customer reliability benefits and that where reliability benefits were broken out by customer class about 97% of those benefits would accrue to commercial and industrial customers. Witness Thomas testified that DEP's cost estimates for the GIP programs were of a high-level nature, and that actual costs could vary widely from such estimates. He pointed out other concerns with DEP's cost-benefit analyses but ultimately did not recommend rejection of any of them. He recommended that GIP expenditures be tracked and reported, that DEP perform cost-benefit analyses for additional GIP programs, that it file sensitivity analyses of its cost-benefit analyses that include cost variations, and that it remove or modify benefits in its analyses, including long-term reliability benefits, CO_2 emission savings, avoided capacity planning margin requirements gross-up, and avoided capacity in years when no capacity is needed. He recommended that DEP consider conducting a study to more

[10] On April 23, 2020, witness Maness filed supplemental testimony in which he made slight adjustments to his ROE calculations, which he described as impacting 2021 and 2022 results by one basis point, an amount "that does not affect the recommendation in my initial testimony."

accurately reflect its customers' outage costs. In addition, witness Thomas recommended that DEP revise its analysis for the Transmission Hardening and Resiliency program to assign reliability benefits to customer classes. He stated that DEP should revise the Self-Optimizing Grid cost-benefit analysis to include the effect of momentary outages and the expected reduction in vegetation-related outages from increased vegetation management. Thomas said DEP should consider how GIP investments would impact other costs, such as inventories, and that DEP and the Commission should consider changing the allocation of GIP costs among customer classes.

Witness Thomas recommended that DEP reduce the scope of the DSDR[11]-to-CVR conversion project in order to determine the amount of peak shaving that would be lost by full conversion. He stated that DEP intends to seek relief from its current DSDR peak shaving obligation. He stated further that DEP had not estimated the amount of peak reduction that will be lost by the conversion, "therefore its CBA [cost benefit analysis] does not represent an accurate estimate of the benefits to ratepayers." Witness Thomas stated that "DEP should proceed in a manner that will ensure that the decision to reduce peak shaving capabilities, particularly in the winter, does not cost ratepayers more than anticipated."

Public Staff witness James McLawhorn stated that the benefits derived from some of the GIP transmission and distribution assets are disproportionately related to the way the GIP transmission and distribution plant is allocated. He believes this area of cost allocation deserves further study.

NCJC. et al. Testimony

Witness Stephens reviewed DEP's proposed GIP, including its cost-benefit analyses. He identified deficiencies in some of the analyses and a lack of justification for other GIP programs. He recommended that the Commission reject DEP's GIP and establish a separate proceeding for developing a new GIP plan and budget. He identified eight of DEP's GIP programs that merit approval, with conditions, because they represent standard industry practice, consist of software that is needed to optimize grid assets, operations, or cyber security, are likely to deliver benefits to ratepayers in excess of costs, or are critical to provide stakeholders' value that cannot be otherwise secured. These eight programs are: (1) Integrated Volt/VAR Control; (2) the flood and animal mitigation portions of Transmission Hardening and Restoration; (3) Long Duration Interruptions/High Impact Sites; (4) Foundational software including Enterprise Applications, Integrated Systems and Operations Planning (ISOP), and Distributed Energy Resource Dispatch; (5) Cyber Security (excluding substation physical security); (6) Enterprise Communications (excluding mission critical voice and data network); (7) Power Electronics for Volt/VAR Control; and (8) Automated Distribution Management System.

[11] DSDR stands for distribution system demand response.

Witness Stephens stated that the Self-Optimizing Grid (SOG) program should be approved but at a reduced level to focus on circuits that would experience the greatest benefit. As to the Transmission Hardening and Restoration program, he stated that the entire budget should focus on projects to accommodate more distributed energy resources.

Witness Stephens testified that the Commission should reject the following programs because they are not generally cost-effective: (1) Targeted Undergrounding; (2) Distribution Transformer Retrofits; (3) Transformer Bank Replacements; (4) Oil-filled Breaker Replacements; and (5) Substation Physical Security. Witness Stephens recommended that the Commission require on-going performance measurement for DEP's GIP initiatives as well as cost caps and operating audits.

In addition, witness Stephens recommended that the Commission reject the Mission Critical Voice and Data Network Development Programs because Duke Energy conducted no make-versus-buy evaluation of alternatives to its own $160-million proposal to build proprietary voice and data networks. Similarly, Stephens said DEP provided no cost-benefit analyses for its Distribution Automation and Transmission System Intelligence programs.

Witness Alvarez criticized DEP's reliance on the LBLN Report for estimating outage costs; he said the report is based on old data that is geographically biased and biased toward manufacturing and retail businesses that have the highest outage costs of all commercial and industrial segments. Further, the surveys used to collect outage cost data did not consistently address the availability of back-up generators and uninterruptible power supply systems. Alvarez asserted that DEP over-estimated the GIP's benefits by overstating the number of outages being avoided by the programs, then by overstating the economic benefits of those avoided outages, and finally by using those overstated primary benefits as inputs to the IMPLAN software, which estimated the secondary benefit of the GIP. Further, he contended that DEP did not estimate the detrimental impacts on North Carolina's economy of the significant rate increases that the GIP would generate. He asserted that the GIP would cause a 3.8% rate increase, that residential customers would likely be allocated about 59.2% of the costs, and that they would pay at least $10.44 for every $1 in benefits that they receive. On the other hand, he asserted that Duke Energy's shareholders would likely earn $2.6 billion in return on equity over 30 years, or $1.2 billion in present value terms, from its GIP investments. He testified that DEP's GIP will ultimately cost ratepayers $8.6 billion over 30 years, or $3.4 billion in present value terms. He also asserted that the GIP presents an asymmetrical risk profile, one in which ratepayers take all the risk for benefit delivery and cost overruns, while shareholders earn a rate of return under all scenarios. He recommended that the Commission reject DEP's GIP and its request for deferral accounting and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process.

CIGFUR Testimony

Witness Phillips testified that there is no compelling evidence demonstrating that grid improvements warrant a departure from standard ratemaking practices. Further, he asserted that DEP's plan would shift regulatory risk from its investors to customers as well as allow DEP to pursue single-issue ratemaking. He testified that the deferral, if approved, could eliminate DEP's incentive to prudently manage costs between rate cases, and that GIP costs are not volatile or unpredictable. Phillips stated that if the deferral is approved, DEP's allowed ROE should be reduced to reflect the reduced business risk that its investors will face.

CUCA Testimony

Witness O'Donnell testified that DEP's proposed grid expenditures are too expensive and lack customer support. He stated that many of the programs lack cost-benefit analyses to prove that they are beneficial and should therefore be disallowed. He stated that the Commission should only allow recovery of GIP program costs where promised reliability benefits are achieved.

Witness O'Donnell testified that regulated utilities have an incentive to build plant, and that DEP offered no performance guarantees. He asserted that Duke Energy intends to pursue its Power Forward grid initiative, of which GIP is a part, and that this $13 billion 10-year grid modernization effort will cause massive rate increases. He asserted that a typical DEP industrial customer would pay $4.1 million more over 10 years due to DEP's GIP investments.

Harris Teeter Testimony

Witness Bieber recommended that the Commission reject DEP's proposal to defer GIP costs. He stated that deferral is unnecessary and would amount to single-issue ratemaking. Bieber testified that DEP's GIP costs do not appear to be volatile or outside the Company's control, and that they should be considered in the context of general rate cases.

NC WARN Testimony

Witness Powers recommended that the Commission reject DEP's GIP proposal, stating that the stakeholder workshops that DEP hosted were essentially sales presentations. He stated that the high cost of the GIP is such that additional rigorous review is needed to protect ratepayers. He testified that the GIP presumes that there is only one pathway to grid modernization and that other alternatives should be considered. For example, installing battery storage in residences would be a less costly way to improve reliability than the Targeted Undergrounding program that DEP proposed.

Vote Solar Testimony

Witnesses Nostrand and Fitch testified that DEP's GIP does not assess or respond to climate-related risks, and it does not adhere to grid modernization best practices. They recommended that the Commission: (1) direct DEP to assess and manage climate-related risks across its operations and assets; (2) make clear that it will apply this standard to GIP investments; (3) direct DEP to participate in Department of Environmental Quality stakeholder processes around grid modernization, and integrate data, findings and recommendations into its GIP; (4) require DEP to file a report identifying gaps in knowledge that need to be filled through further collaboration; (5) require DEP to develop a GIP through an integrated distribution planning process; and (6) if GIP deferral is allowed, impose performance-based conditions on the recovery of the deferred amounts.

DEP Rebuttal Testimony

Witness Oliver stated that none of the intervenor witnesses dispute the megatrends that are driving the need for the GIP.

As to the Public Staff's assertion that some GIP programs do not meet the definition of grid modernization, Oliver argued that each program within the GIP seeks to bring the current grid up to new standards of operation or reliability. He then used the same matrix and methodology for analyzing GIP programs that the Public Staff had developed, scored the programs higher for some attributes, and concluded that these programs should be added to the Public Staff's list of "extraordinary" programs:

(1) SOG Capacity and Connectivity;

(2) DSDR Conversion to CVR;[12]

(3) Distribution Automation (the Underground System Automation subprogram was already included in the Public Staff's list);

(4) Power Electronics;

(5) Distributed Energy Resource Dispatch Tool; and

(6) Cyber Security

[12] The Commission notes that DEP's GIP is inconsistent as to its proposed treatment of new GIP-driven DSDR-related costs. While the CVR conversion costs are included in the deferral requested in this rate case, DEP apparently plans to recover other DSDR-related GIP costs in the Company's DSM/EE rider. Oliver Exhibit 10 states that next generation cellular and capacity bank control replacements "associated with DSDR assets will not be recovered under GIP but instead will be separately evaluated and recovered under the [DSDR] rider." *See* Oliver Ex. 10, at 51, 90.

Where the Public Staff's list of five "extraordinary" programs totals $186.1 million in capital spending from 2020-2022, Oliver's six programs would add $248 million to that amount, for a total of $434 million. As to the other programs, Oliver stated that the Public Staff's evaluation method is one rational approach but it is not the only way to evaluate programs. Oliver asserted that all of DEP's GIP initiatives meet the definition of grid modernization and all their costs should be eligible for deferral.

The costliest GIP program that the Public Staff disputed is SOG at $302 million in capital over three years. Oliver stated that SOG is an example of a GIP project that addresses all the megatrends, not just reliability. He said that when privately owned roof-top solar becomes widespread, a dynamic, automated, capacity-enabled two-way power flow grid will be essential. During lightly loaded shoulder seasons, SOG would allow excess DER energy to be routed to adjacent neighborhoods for use, maximizing its value and reducing line losses.

Witness Oliver asserted that SOG will allow DEP to defer capacity. He stated further that DEP plans to deploy SOG on circuits where it will have the most benefit. Since that deployment will increase DEP's efficiency when responding to outages, it will benefit all customers. Witness Oliver disagreed with Public Staff witness Thomas' assertion that SOG will result in an increased number of momentary outages.

Witness Oliver responded to witness Thomas' concern that SOG benefits are overstated because DEP failed to consider the reduced number of vegetation-related outages that will occur due to DEP's tree trimming plans. He noted that Thomas stated that he believed that any such impacts would be even less on DEP's system than on DEC's, where the impacts were only two percent. In addition, DEP's cost-benefit analysis for SOG did not include any benefits for improving reliability on major event days. He said that SOG is a "no regrets" investment that provides significant value for customers in multiple ways.

As to the Public Staff's concern that the DSDR-to-CVR conversion will result in lost peaking capacity, witness Oliver stated that DEP agrees with witness Thomas that the amount of peak reduction lost by the conversion will require further analysis. He argued, however, that converting DSDR to CVR now is critical to enable the greater use of distributed energy resources. A delay in the conversion would reduce the grid's ability to respond to the growing penetration of solar generation. Operating in CVR mode will provide increased visibility into the status and condition of substation and field devices to help respond to intermittency. In addition, the conversion will result in greater fuel savings than is currently provided by DSDR.

Witness Oliver responded to witness Alvarez' assertion that Duke Energy's GIP cost-benefit analyses contain $425 million in capital spending that is not included in Duke's three-year capital spending. Oliver stated that it is not accurate to compare the capital budget spending plan in his Exhibit 10 to the costs in DEP's GIP cost-benefit analyses because they serve different purposes. He stated that some of the cost-benefit analyses are for projects or programs that start in the 2020-2022 period but continue into 2023 and beyond.

Oliver stated that the majority of the $1.1 billion in software and communications replacement costs identified by Alvarez are justified under cost-effective guidelines instead of via a cost-benefit analysis. He said that there is no need to evaluate all programs over the same lifecycle.

As to witness Alvarez' assertions that Duke Energy did not consider alternatives for its $160 million in communications network investments, witness Oliver said Duke Energy followed documented enterprise supply chain processes, including requests for information and requests for proposals, to evaluate alternatives. He said that, where appropriate, considering the cost, security, speed to deploy and level of service required, external carriers provide services to Duke Energy's networks. He testified that core data network requirements exceed the current capabilities that third-party cellular providers can provide, given their bandwidth limitations. Oliver stated that for the Land Mobile Radio program, alternative services were considered, and bidders were eliminated because of their inability to meet requirements.

Oliver disagreed with witness Alvarez' assertion that DEP's cost-benefit analyses overstate benefits to C&I customers, calling this assertion misleading. As to Alvarez' critique of DEP's IMPLAN analysis, Oliver stated that the impact of rate increases was outside the scope of that analysis.

Oliver asserted that the cost-benefit analyses included in his direct testimony provide metrics for the programs, such as the amount of O&M savings DEP anticipates, the amount of avoided capital costs DEP anticipates, and the number of outages each program is anticipated to avoid. He said that DEP will track project/program scope, schedule, cost, and benefits as appropriate during implementation.

In response to witnesses who argued that DEP's transformer retrofit, bank replacements, breaker replacements, and transmission line rebuilds were not appropriate grid modernization initiatives, and that they are business-as-usual activities, Oliver stated that the GIP accelerates the pace of these efforts to better position DEP to deal with future requirements.

As to DEP's Targeted Undergrounding program witness Oliver acknowledged that its scope had been scaled back by about 90%. He said the remaining program is highly cost beneficial. He disagreed with witnesses who asserted that Targeted Undergrounding is not standard industry practice and stated that both Dominion Energy in Virginia and Florida Power & Light in Florida have similar programs.

As to DEP's plans to upgrade the security of substations Oliver stated that DEP used a graded approach to physical security at substations not covered by NERC CIP-014, NERC's physical security standard. Oliver stated that most substations will not need security improvements.

In response to critics of Duke's grid modernization stakeholder process Oliver stated that DEP used the feedback received in the workshops to validate the megatrends, conduct additional analyses, drive future workshop discussions, and make significant changes to the portfolio of investments.

He stated that the GIP is a three-year plan, while Power Forward was a ten-year plan, and that the scope of the two plans is dramatically different. He noted that Distribution Hardening and Resiliency and Targeted Undergrounding made up 64% of Power Forward but are only 11% of the three-year GIP and also stated that GIP contains several new programs, specifically the conversion of DSDR to CVR, and the addition of Cyber Security. He stated that Self-Optimizing Grid is generally supported by all stakeholders, made up less than 10% of Power Forward, but is the largest program in the three-year GIP, making up over 31% of the total. Oliver stated further that the GIP begins to prepare the North Carolina grid for growth in privately owned distributed energy resources and electric vehicles, but even if this growth does not occur, the plan still is cost effective. He stated further that there is currently no "Phase 2" of the plan, and that any future plan would be based on collaboration with stakeholders.

Witness Oliver acknowledged that the GIP does not address third-party owned DER accommodation in North Carolina. He stated that while some GIP programs and projects provide ancillary benefits to interconnection issues, those benefits are secondary to the programs' primary purposes.

Witness Oliver recommended that the Commission ignore witness Alvarez' recommendation to reject the GIP and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. Oliver referred to Exhibit 3 of his direct testimony, which lists six negative implications of a business-as-usual response to DEP's identified megatrends:

(1) Increased costs;

(2) Reduced reliability and resiliency;

(3) Reduced ability to manage and integrate distributed energy resources;

(4) Reduced ability to meet customer expectations and commitments;

(5) Reduced economic competitiveness for North Carolina; and

(6) Increased geographic and demographic disparity.

Witness Oliver stated that if the Commission were to reject the Company's deferral request, the work in the GIP would have to be sub-optimized, delayed, diminished in scope and effectiveness, and potentially not done at all.

Similarly, witness Oliver rejected arguments that the GIP should be delayed until an IRP or ISOP process is conducted. He asserted that delay could hinder the ability of ISOP to deliver benefits, and he stated that Duke is already engaging stakeholders to develop the ISOP process.

DEP witness Smith responded to witnesses who expressed concern about the ratemaking aspects of DEP's GIP deferral request. She asserted that cost recovery is a separate and distinct process from deferral of costs. She stated that deferral would allow DEP the opportunity to avoid adverse financial impacts of regulatory lag, but only to the extent the Commission ultimately allows recovery of the deferred costs in a future proceeding. Witness Smith stated that even if DEP were allowed to defer its GIP costs, the Company would still bear the risk of recovering the costs in a future rate proceeding.

Witness Smith clarified that DEP is not requesting deferral of its GIP capital expenditures. Rather, DEP is requesting to defer the traditional revenue requirement amounts associated with the GIP capital expenditures. She stated that when the Company makes capital investments as part of the GIP, the cost to be deferred would be the depreciation and return on investment for the completed plant in service. She stated that if the Company spends $1.2 billion in capital over a three-year period, the deferred cost associated with that amount is not $1.2 billion, but instead is three years of annual depreciation and return on that investment, beginning at the date the assets are completed and in service. She explained further that the deferral would include the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when Company rates are updated to include cost recovery of the assets.

Witness Smith disagreed with those witnesses who asserted that deferral would cause customers to bear the risk of cost overruns or GIP scope shortcomings. She stated that the Commission has full authority to address cost overruns or scope issues during a future general rate case when the deferred costs are presented for recovery, and that DEP bears the full risk of any disallowances that the Commission could choose to impose. During the consolidated evidentiary hearing witness Smith stated that the costs would be deferred over the three-year period, and in DEP's next general rate case all the deferred costs will be reviewed by the intervenors and the Commission. "And the Commission, at that time, will decide" whether the "costs we incurred were reasonable and prudent." She said that the costs witness Oliver has presented are estimates, "and as in any investment that the Company makes where we do a budgeted amount and then we have actuals … people go through and look at why it was different . . . . That analysis is normally done by the intervenors." Consolidated Tr. vol. 6, 106-107.

In summary, witness Smith stated that by hosting its stakeholder process as directed by the Commission in the 2018 DEC Rate Order DEP was able to assure that the GIP programs constitute grid modernization and hence are extraordinary, as opposed to customary spend. She testified further that absent deferral DEP's GIP spending would cause it to experience significant adverse earnings impacts. She stated that the three-year GIP comprises numerous projects that have a short construction period and therefore will be quickly placed into service. "Given the length of time to complete a general rate case, even if the Companies had rate cases every year, the delay in cost recovery from the month that the grid improvement is placed in service to the month that the costs are reflected in the Companies' new base rates could be significant, on average more than a year." Witness Smith testified further that the Commission has demonstrated that "deferral is not a rigid concept but can be flexibly applied to ensure that the Commission fulfills its fundamental mandate to set rates that are just and reasonable and fair to both the Companies and their customers." Consolidated Tr. vol. 6, 88-89.

During the consolidated portion of the hearing, DEC witness Jane McManeus stated that, having "been granted a regulatory deferral as a regulatory asset, . . . I think that's sort of a nod from the Commission to say we understand the costs you're talking about and we don't view them as inappropriate programs or inappropriate electric expenses that one should not ever recover from a customer, assuming that they are reasonable and prudently incurred." When asked, witness Smith said that she agreed with witness McManeus' testimony. Consolidated Tr. vol. 9, 24.

Witness Smith stated further that DEP had spent almost $280 million on GIP from January 2018 through May of 2020. Consolidated Tr. vol. 9, 33. No party disputed these costs.

During the consolidated evidentiary hearing, witness Oliver stated that the Company's capital spending estimates for the GIP programs relied on unit cost estimates that involve a range of cost uncertainty from -20% to +30%. Consolidated Tr. vol. 10, 23.

Public Staff Second Partial Stipulation

In the Second Partial Stipulation the Public Staff agreed to support deferral for the following GIP programs: (1) Self-Optimizing Grid (all programs including capacity, connectivity, segmentation, and automation), (2) conversion of DSDR to CVR, (3) Integrated Systems and Operations Planning, (4) Transmission System Intelligence, (5) Distribution Automation, (6) Power Electronics, (7) DER Dispatch Tool, and (8) Cyber Security. For all other GIP programs, DEP agreed to withdraw its request for deferral accounting.

The Public Staff and DEP agreed that the Second Partial Stipulation constitutes only approval of the decision to incur GIP costs; the Public Staff reserved the right to review actual costs for reasonableness and prudence in the future. DEP and the Public Staff agreed to jointly develop biannual reporting requirements to track GIP expenditures that receive deferral treatment. This will include: (1) tracking costs for each program, including the number of devices installed, types of projects completed, or circuits modified or impacted; (2) reporting on a circuit and substation level; (3) summarizing actual benefits compared to projected benefits; (4) reporting the operational system impacts of Self-Optimizing Grid and Integrated Volt/VAR Control; and (5) providing data and analyses that inform any significant changes to the scope of the Self-Optimizing Grid and

Integrated Volt/VAR Control programs. The first report would cover spending in the last six months of 2020.

DEP agreed to assess the cost effectiveness of GIP projects in an on-going manner and to undertake a cost-benefit analysis for its automated lateral device program.

Further, GIP deferral would be restricted to capital costs (return, property tax, and depreciation) related to plant in service and incremental expenses net of operating benefits, for plant placed in service between June 1, 2020, and December 31, 2022, and a return on the deferred balance. Deferral would cease upon the effective date of any general rate case order in which the associated eligible plant is included in rate base. If no general rate case order recognizing the entirety of eligible plant in rate base is issued by December 31, 2024, DEP would cease deferral of all eligible net costs and carrying costs and consult with the Public Staff regarding the beginning of amortization of the deferred costs for regulatory accounting and ratemaking purposes. Under the Second Partial Stipulation, GIP deferral would not include overhead or administrative and general costs, but the capitalized project costs may include a reasonable allocation of management and supervision costs.

During the consolidated portion of the evidentiary hearing, DEP witness Oliver stated that the Second Partial Stipulation with the Public Staff neither has a spending cap nor includes performance guarantees. Consolidated Tr. vol. 6, 33-34, 68.

Witness Smith stated that the ROE impact for the eight GIP programs in the Second Partial Stipulation was a cumulative impact of 59 basis points in year three if the Commission were to deny the deferral, but DEP nonetheless pursued those programs. Consolidated Tr. vol. 9, 37. Witness Oliver said that the benefits of the programs, as stated in his direct testimony Exhibit 7 cost-benefit analyses, would be tracked under the Second Partial Stipulation. Consolidated Tr. vol. 6, 16. Witness Oliver also stated that DEP will implement GIP regardless of whether the Commission approves the Company's deferral request. However, the deferral would give DEP the ability to implement the GIP programs in a more cost-effective manner. *Id.* at 56.

CIGFUR Stipulation

In the CIGFUR Stipulation CIGFUR agreed to support DEP's GIP deferral request but reserved the right to review and object to the reasonableness of specific project costs in future rate cases. DEP agreed to propose to allocate GIP costs using the minimum system method and voltage differentiated allocation factors for distribution plant.

Commercial Group Stipulation

In the CG Stipulation Commercial Group agreed not to oppose or support DEP's GIP deferral request. DEP agreed that any GIP costs that are allocated to its SGS-TOU customers shall be recovered via SGS-TOU demand charges.

Harris Teeter Stipulation

In the HT Stipulation Harris Teeter agreed to support approval of GIP deferral but is not precluded from taking any position in future cost recovery proceedings regarding the reasonableness of specific GIP costs. DEP agreed that any GIP costs allocated to SGS-TOU customers shall be recovered via SGS-TOU demand charges.

Vote Solar Stipulation

In the Vote Solar Stipulation Vote Solar agreed to support DEP's deferral of costs for the following GIP programs: ISOP, DSDR, SOG, Distribution Automation, Transmission System Intelligence, DER Dispatch Tool, and the 44-kV Line Rebuild[13]. The Vote Solar Stipulation stated that Vote Solar believes that these investments will enable and support the greater use of distributed energy resources. Vote Solar agreed not to oppose deferral of the other GIP programs' costs. Further, "to the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap," Vote Solar supported such cost containment measures. DEP committed to develop potential pilot GIP customer programs to increase the use of distributed resources prior to submission of its 2022 IRP. If DEP and Vote Solar agree that these programs are cost effective and meet Commission requirements, DEP agreed to file them for approval, and Vote Solar agreed to support such approval. Vote Solar reserved its right to review and object to specific project costs in future rate cases.

NCSEA/NCJC et al. Stipulation

In the NCSEA/NCJC et al. Stipulation NCSEA and NCJC et al. agreed to support DEP's deferral request for: (1) ISOP, (2) DSDR, (3) SOG, (4) Distribution Automation, (5) Transmission System Intelligence, (6) DER Dispatch Tool, and (7) 44-kV Line Rebuild, stating that these programs will enable and support greater use of DER. For all other GIP investments, NCJC et al. did not oppose deferral.

For its part DEP agreed that congestion relief will be a primary criterion in planning and decision-making regarding future transmission and distribution investment, and that DEP will implement the basic elements of ISOP in its 2022 IRP. Following the 2024 IRP, DEP agreed that it will provide hosting capacity analyses for a sample of circuits, contingent on the Commission approving recovery of the costs. In addition, DEP agreed to preview a distributed generation guidance map with the TSRG in third quarter 2020, incorporate input and publish it. Finally, DEP agreed that its 2021 IRP will include details of how DERs and non-wires applications will be examined in ISOP.

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[13] Oliver Exhibit 7 details expenditures for GIP upgrades to the DEC 44-kV system but not to the DEP system; it is the Commission's understanding that there are no 44-kV transmission resources on the DEP system.

During the consolidated portion of the evidentiary hearing witnesses Alvarez and Stephens agreed that the programs supported by NCSEA and NCJC et al. would support renewable energy deployment or improve reliability. Consolidated Tr. vol. 8, 97.

DEP Joint Testimony

On August 5, 2020, DEP witnesses Oliver and Smith filed joint testimony and exhibits in response to a July 23, 2020 Order in which the Commission directed DEP to file supplemental GIP economic analyses. The DEP analyses showed the revenue requirement and rate impacts of approving deferral for the smaller group of GIP projects covered in the Second Partial Stipulation between DEP and the Public Staff. Page 1 of GIP Exhibit 3 – Deferral Granted (Settlement) of that testimony showed that, under the Second Partial Stipulation, deferral and a subsequent rate case in 2024 would produce a revenue requirement of $69.9 million in 2024, and a rate increase at that time of 2.8% for residential customers, 2.6% for small general service customers, and 0.4% for large general service customers. This analysis used the ROE and capital structure agreed to in the Second Partial Stipulation.

Witness Oliver testified that if the Commission does not grant deferral accounting, the Company would likely vary its GIP spending from year to year, performing smaller pieces of GIP over a much longer timeframe, which would delay benefits for customers. He stated that the deferral mechanism would give DEP the ability to implement the GIP programs in a much more cost-effective, planned-out way, and to bring the benefits to customers sooner. Further, the deferral would allow DEP to accelerate the historical pace of GIP spending to better position DEP for the future. Consolidated Tr. vol. 6, 45-46.

Witness Oliver testified that in order to perform GIP work at the pace and scope that provides the most benefit to customers, DEP needs new and modern ways to recover costs and avoid the regulatory lag that can harm the Company's financial metrics and, in turn, customers.

Witness Oliver further testified that DEP's GIP programs "are the core of grid modernization," because they provide for two-way power flows, advanced distribution planning, the ability to control VAR flow from a central hub, the ability to control voltage at substations and on lines, and the ability to leverage AMI meter information. He said these are foundational to building a modernized grid. Making these investments now will make ISOP more effective than it would otherwise be. Consolidated Tr. vol. 10, 30.

DEP Late Filed Exhibit 5

On September 8, 2020, at the request of Commissioner Hughes during the consolidated evidentiary hearing, DEP filed Late Filed Exhibit 5, which shows the revenue requirement savings that DEP expects from the GIP programs agreed to in the Second Partial Stipulation. That unverified exhibit shows a revenue requirement reduction of $6.4 million in 2023, and $7 million in 2024, growing to $27.6 million in 2032. The exhibit showed that the majority of the benefits in 2032 ($17 million) are due to fuel savings from the DSDR to CVR conversion initiative.

Public Staff Supplemental Testimony

In his September 15, 2020 supplemental testimony Public Staff witness Tommy Williamson testified that during the update period of March – May 2020, DEP closed to plant at least $52.8 million of GIP investments. He stated that about $15.8 million of that was for SOG segmentation and automation projects on 135 circuits. The Public Staff sampled ten of those circuits and discovered that only three of them were fully enabled with SOG functionality. He stated that the remaining seven require additional reclosers and circuit enablement and are expected to be fully enabled in 2021. Williamson stated that DEP had told the Public Staff that the personnel who program the software to enable each segment had not been able to keep up with the increasing pace of expenditures. Williamson concluded that these investments nonetheless are "used and useful" and eligible for inclusion in rate base, even though they were not fully enabled.

DEP Supplemental Rebuttal Testimony

Witness Oliver responded to witness Williamson's supplemental testimony by stating that the timeframe is longer than Duke would like between construction completion and enablement of SOG segmentation and automation projects. He stated that once DEP is fully staffed it will take about 12 weeks between construction work completion and enablement. Oliver said that these 12 weeks are needed to schedule multiple interdependencies between the reliability engineers who create the device settings, the model builders who program the devices into the software and facilitate testing and validation, and coordination with grid management technicians to ensure devices present correctly in the distribution control center. Witness Oliver testified that as COVID restrictions ease DEP intends to begin building the staff required to reach the targeted 12-week timeframe. He stated that meeting the 12-week timeframe can be an additional metric tracked pursuant to the Second Partial Stipulation with the Public Staff.

Discussion and Conclusions

In Sub 1142 DEP did not seek recovery of any GIP (Power Forward) costs, although Public Staff witness Floyd testified that the Company had already spent $18.2 million on such investments. At that time, DEP planned to spend $1.6 billion in capital from 2017 through 2021 on grid modernization. Several parties urged the Commission to establish a separate proceeding to resolve the scope and pace of DEP's grid modernization efforts, which the Commission declined to do. Instead, the Commission approved a stipulation between DEP and the Public Staff that required DEP to host a technical workshop regarding the Company's Power Forward grid investments.

Power Forward was also an issue in DEC's 2018 general rate case, Sub 1146. In that proceeding the Commission rejected DEC's request for either a rider or deferral accounting for Power Forward expenditures and suggested that DEC collaborate with stakeholders in developing any future grid improvement programs.

In the current DEP rate case, witness Oliver testified that, in response to the Commission's recommendation in the DEC 2018 Order, the Company convened three in-person stakeholder workshops and a series of webinars addressing the Company's plans for grid improvement. Tr. vol. 16 at 144-45. Witness Oliver stated that the Rocky Mountain Institute acted as a neutral facilitator in each of the three workshops and prepared detailed, post-project reports that were filed with the Commission at the conclusion of each workshop. *Id.* at 145. Witness Oliver testified that because of these stakeholder engagements the Company made significant changes to its portfolio of investments, provided cost-benefit analyses and underlying data sources and worksheets for all applicable programs and projects to stakeholders, and responded to questions concerning distributed energy resources. *Id.* at 145-46. The Commission recognizes the effort expended by the Companies to engage with stakeholders, as the Commission had directed them to do.

In the instant proceeding, subsequent to its initial request for approval to defer costs related to $987.8 million in spending on 16 programs aimed at addressing its grid modernization needs, DEP worked with the Public Staff to reduce further its planned investment, and the Public Staff agreed to DEP's requested deferral accounting treatment for that investment. Specifically, DEP seeks deferral of the capital costs associated with GIP investments made from June of 2020 through December of 2022 for the following programs, the descriptions for which are derived from witness Oliver's direct testimony (including his Exhibit 10), and augmented with testimony from the consolidated portion of the evidentiary hearing:

(1) SOG. This initiative has three components: capacity, connectivity, and automation. Capacity projects expand substation and distribution line capacity to allow customers to be served from two directions. Connectivity projects create tie points between circuits. Automation projects provide intelligence and control, enabling the grid to dynamically reconfigure around trouble and better manage distributed energy resources. The advanced distribution management system is software that leverages the intelligence from the grid with information from substation equipment, intelligent switches, and distributed energy resources to optimize power flow and minimize the impact to customers when faults occur. It is the centralized system for managing the grid.

(2) Integrated Volt/VAR Control (IVVC). Allows the distribution system to optimize voltage and reactive power via remotely operated substation and distribution line devices such as voltage regulators and capacitors. The grid operator can lower the voltage to reduce energy consumption and system losses. Witness Oliver stated that DEP plans to convert its DSDR system[14] to operate in

[14] The Commission approved DSDR as an energy efficiency program in 2009 in Docket No. E-2, Sub 926. DEP files annual DSDR reports in that docket, most recently on July 14, 2020. That report shows

conservation voltage reduction (CVR) mode at a cost of $10 million. During the consolidated portion of the hearing, witness Oliver testified that DEP plans to test the impact that the DSDR-to-CVR conversion would have on the system's load reduction capability. Consolidated Tr. vol. 6, 26.

(3) Distribution Automation. Includes four programs. The hydraulic-to-electronic re-closer program involves the replacement of oil-filled devices with modern, remotely operating reclosing devices that support continuous system health monitoring. The fuse replacement program replaces one-time-use fuses with automatic devices that reset themselves. The underground system automation program modernizes the protection and control in underground systems that serve critical, high-density areas such as urban business districts and airports. The system intelligence and monitoring pilot develops advanced diagnostic tools that help engineers and technicians address electrical disturbances on the distribution system.

(4) Transmission System Intelligence. DEP will replace electromechanical relays with remotely operated digital relays, implement intelligence and monitoring technology capable of providing asset health data to drive predictive maintenance programs, deploy remote monitoring and control of substation and transmission line devices, and install resiliency projects that leverage state of the art equipment such as digital relays, gas breakers, and other equipment enabled with SCADA communication and remote monitoring and control capabilities to rapidly respond to system outages or disturbances.

(5) ISOP. Involves the integration and refinement of existing system planning tools and the development of new analytical tools. It is a multi-year program to build and integrate the tools and processes needed to accommodate an integrated approach to plan and operate the electric utility system. One example is the Morecast circuit level load forecasting tool, which is necessary to enable the Advanced Distribution Planning tool.

(6) DER Dispatch Tool. Will provide system-wide visualization and control of large-scale DERs, enabling DEP to model, forecast, and dispatch them. It will provide operators with a more automated and refined toolset to optimize management of both utility- and customer-owned DERs to meet system stability requirements.

(7) Power Electronics for Volt/VAR Control. This limited deployment of advanced solid-state technologies like static VAR compensators will help DEP manage power quality issues associated with increasing DER penetration.

that in 2019, DEP used DSDR to reduce demand 14 times, achieving between 87 MW and 260 MW of peak reduction each time, and 7,785 MWh of total energy savings.

(8) Cyber Security. These programs include cyber security enhancement, protection from electromagnetic pulses and electromagnetic interference, a device entry alert system, and distribution line cyber protection and secure access device management. Consolidated Tr. vol. 5, 39.

The Second Partial Stipulation constitutes agreement between the Public Staff and DEP as to the decision to incur GIP costs and the deferral accounting treatment of those costs. The Public Staff expressly reserved the right in the agreement to review actual costs incurred by DEP for reasonableness and prudence in future proceedings. Additionally, DEP and the Public Staff agreed to develop jointly biannual reporting requirements to track GIP expenditures that receive deferral treatment, including: (1) tracking costs for each program, including the number of devices installed, types of projects completed, or circuits modified or impacted; (2) reporting on a circuit and substation level; (3) summarizing actual benefits compared to projected benefits; (4) reporting the operational system impacts of SOG and IVVC; and (5) providing data and analyses that inform any significant changes to the scope of the SOG and IVVC programs. The first report would cover spending in the last six months of 2020. Additionally, DEP agreed to assess the cost-effectiveness of GIP programs in an on-going manner and to undertake a cost-benefit analysis for its automated lateral device program.

Further, the Public Staff and DEP agreed that the costs deferred would be limited to only capital costs (return, property tax, and depreciation) related to plant in service and incremental expenses net of operating benefits, for plant placed in service between June 1, 2020, and December 31, 2022, as well as a return on the deferred balance of such costs during the deferral period. The deferral would cease upon the effective date of any general rate case order in which the associated eligible plant is included in rate base. The Public Staff and DEP agreed that if no general rate case order recognizing the entirety of eligible plant in rate base is issued by December 31, 2024, DEP would cease deferral of all eligible net costs and carrying costs and consult with the Public Staff regarding the beginning of amortization of the deferred costs for regulatory accounting and ratemaking purposes.

In addition to the Second Partial Stipulation with the Public Staff, DEP reached five settlements with multiple other parties relative to its GIP deferral request. Several of those settlements address cost allocation issues related to costs incurred for the GIP programs, which are not ripe for decision by the Commission at this time. Because the issues of cost allocation for costs associated with the GIP programs are not before the Commission for a determination in this proceeding, the Commission considers them to be properly reserved for the cost recovery proceeding, which would be DEP's next general rate case.

Under North Carolina law, a stipulation entered into by less than all parties in a contested case "should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding." *CUCA I,* 348 N.C. at 466. Further, "[t]he Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." *Id.*

Because of the structure and scope of the stipulations reached with the various settling parties, the Commission concludes that the GIP programs for consideration are those contained in the Second Partial Stipulation, which includes a commitment by DEP to withdraw its request for deferral accounting treatment for individual GIP programs that are not specifically supported by the Second Partial Stipulation. The settlements with the other intervenors either provide express support for or non-objection to the deferral of costs associated with the programs specifically agreed to in the Second Partial Stipulation.

The Commission understands the Second Partial Stipulation, considered together with the settlements reached between DEP and other intervenors, to have resolved GIP-related issues between DEP and the majority of intervenors that filed testimony relating to GIP issues. The only parties whose active opposition to GIP in the form of filed testimony were not resolved through these settlements are NC WARN and CUCA.

The Commission concludes that the Second Partial Stipulation, as well as the additional settlement agreements, constitute material evidence in this proceeding regarding GIP-related issues and should be afforded significant weight by the Commission.

At the direction of the Commission, the Company engaged with stakeholders to redefine its grid modernization plans following its 2018 rate case proceeding. The scope of the Company's GIP proposal was further narrowed through additional negotiation with the Public Staff, and programs that had been criticized as being routine operation expense as opposed to grid modernization were dropped from the proposal that ultimately was adopted in the Second Partial Stipulation. At the expert witness hearing Public Staff witness Thomas testified that the Public Staff had investigated each program included in the Second Partial Stipulation, focusing on costs and benefits, and has an understanding of what ratepayers are getting, in terms of fuel savings and reduced operational costs. The Commission is persuaded by the testimony of witness Thomas that the Public Staff has an understanding of the operational benefits that have been estimated by DEP and the type of reliability improvements that customers might see, and concludes that the Public Staff entered into the Second Partial Stipulation with this understanding. *See* Consolidated Tr. vol. 7, 69. Also, the Commission gives weight to the testimony of DEP witness Oliver as to his confidence in the cost estimates underlying the GIP proposals as well as cost control measures that the Company will implement. Consolidated Tr. vol. 10, 23-25, 42-43.

The Company and the Public Staff witnesses provided significant reassurance to the Commission that the eight GIP programs included in the Second Partial Stipulation are defined on the record as to scope, implementation, and initial budgets; that the Company has significant experience in implementing similar programs in many cases; and that rigorous project management and evaluation mechanisms will be utilized by the

Company in implementing and monitoring these programs. These mechanisms will include reporting to the Commission at six-month intervals on the progress of such implementation as anticipated in the Second Partial Stipulation.

The test historically utilized by the Commission in assessing the propriety of a request for deferral accounting treatment is whether the costs proposed for deferral are extraordinary in type and extraordinary in magnitude. Tr. vol. 15, 1523. However, this test is not the exclusive basis upon which the Commission has previously allowed deferral of costs incurred by utilities, and, as was noted in the 2018 DEC Rate Order, the Commission may approve a deferral within a general rate case with parameters different from those applied in contexts other than general rate cases. 2018 DEC Rate Order at 149. Unlike the consideration of a deferral request outside a general rate case when a single expense is being brought to the Commission's attention, in a general rate case the Commission has the benefit of a complete picture of the Company's financial health, of all of its expenses and revenues, and the impact of a deferral of future costs on the revenue requirement being approved in that general rate case. Therefore, the typical concerns are not an issue in the present case because the request is not being determined outside of a general rate case, but rather is being determined in a general rate case, a proceeding in which all items of revenue and costs are reviewed.

Additionally, the Commission's 2018 DEC Rate Order declared that "with respect to demonstrated [grid modernization] costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the 'extraordinary expenditure' test." *Id.* Public Staff witness Maness explained that the Public Staff took special notice of the language in the Commission's 2018 DEC Rate Order that suggests leniency regarding the magnitude of costs or financial impacts necessary to justify deferral. Consolidated Tr. vol. 7, 32, 48; Tr. vol. 15, 1600. Further, in explaining why the Public Staff opposed the Company's Power Forward proposal but supported the GIP proposal set forth in the Second Partial Stipulation, witness Maness indicated that the Power Forward rider proposal was not clear on whether and the extent to which costs would be reviewed at the time the Company seeks cost recovery. Consolidated Tr. vol. 7, 44. Public Staff witness Maness also expressed concern at the Company's position that, absent deferral approval, the Company would reduce spending on the GIP programs by 80%. *Id.* at 45. Finally, Public Staff witness Maness testified that the Public Staff "agreed to the settlement in terms of settling all of the issues in the case, and there was give-and-take amongst all of them" and further that "in the interest of settling the case, [the Public Staff] think[s] that it's acceptable for deferral to be approved for the expanded scope of programs that are reflected within the settlement." *Id.* at 49. Witness Maness made clear that the Public Staff was not generally abandoning its initial position in the proceeding, which involved application of the traditional deferral test, but that in the interest of settlement of issues agreed to the GIP proposals as reflected in the Second Partial Stipulation.

Given the evidence of record, the Commission accepts the terms of the Second Partial Settlement as to the GIP proposals, including the request for deferral accounting treatment. However, in approving the request for deferral accounting treatment for the GIP programs set forth in the Second Partial Stipulation, the Commission deems it necessary and appropriate to limit the GIP costs that will be allowed deferral accounting treatment to $400 million, consistent with DEP's planned spending, in order to provide an incentive for DEP to manage its GIP spending cost-effectively and mitigate the risk of over-spending. In light of the fact that the Commission retains the ultimate authority to deny recovery of imprudently incurred or unreasonable costs – even if such costs have been previously deferred – the Commission finds that adequate protections against risks inherent in the design, budgeting, implementation, and monitoring for the eight settled GIP programs are adequately addressed in the record, in the Second Partial Stipulation, and by the implementation of the $400-million limitation on the deferral.

NC WARN witness Powers testified that the Commission should reject the Company's GIP as unreasonable on the basis that the GIP projects are indistinguishable from traditional spend projects, with no formal applications or associated evidentiary process to evaluate the reasonableness or potential alternatives for these proposed expenditures. Witness Powers also contended that the stakeholder workshops used to develop the GIP were essentially sales presentations by the Company that did not adequately review the scope and cost of the GIP. In spite of the contentions of NC WARN, the Commission concludes that the work undertaken by the Company in the stakeholder process to refine its grid modernization proposals and, thereafter, the additional work with the Public Staff to further limit the proposals and associated spending distinguish the proposals from previous proposals. This conclusion is further supported by the uncontested testimony of Company witness Oliver, who described the GIP program proposals as "foundational" to managing the transition from a grid consisting primarily of one-way power flows to a two-way power flow dynamic. Consolidated Tr. vol. 5, 40.

CUCA witness O'Donnell generally took issue with the GIP proposals, expressing concern over costs associated with the programs and the similarity to the Power Forward proposal that had been rejected by the Commission. However, witness O'Donnell did provide several recommendations as to how the Commission should address the GIP proposals, including making cost recovery contingent upon the Company meeting the reliability targets as set forth by DEP in its cost benefit analyses and allowing cost recovery if and only if the reliability targets are reached every year. The Commission notes the concerns expressed by CUCA witness O'Donnell but gives weight to the fact that, per the terms of the Second Partial Stipulation, DEP and the Public Staff will jointly develop metrics to monitor the implementation and measure the effectiveness of the programs. Further, DEP agreed to report such metrics, including cost-effectiveness, for each of the agreed upon programs on a regular basis beginning with expenditures made during the last six months of 2020. On this point, at the expert witness hearing DEP witness Oliver testified that the Company will be able to measure the performance of and the benefits achieved by the programs. Additionally, Public Staff witness Thomas indicated comfort with the parties' ability to measure GIP program performance and confirmed the Public Staff's intention to monitor GIP program performance closely. Thus, the Company has committed to report to the Commission on the effectiveness and cost-effectiveness of the programs. The Commission will hold the Company to this commitment, and the Commission anticipates that these data will be taken into consideration by the Commission in the cost recovery proceedings.

DEP witness Oliver stated that there is currently no ‘Phase 2’ of DEP’s GIP plan, and that any future plan would be based on collaboration with stakeholders. The Commission notes that DEP has embarked on a robust stakeholder engagement effort in order to develop ISOP, which effort the Company described in its Integrated Resource Plan 2020 Biennial Report filed September 1, 2020, in Docket No. E-100, Sub 165. DEP states in that filing that it is committed to implementing the basic elements of ISOP in its 2022 IRP. DEP should ensure that its future grid modernization investments, those occurring beyond 2022, are informed by that ISOP process.

As to the DSDR-to-CVR conversion, the Commission will honor the Second Partial Stipulation between DEP and the Public Staff and allow the conversion costs to be deferred. However, DEP shall nonetheless: (1) determine the amount of peak reduction capacity that will be lost due to the conversion and propose a method of replacing that lost capacity in Docket No. E-100, Sub 165 (IRP docket); (2) file in the IRP docket and Docket No. E-2, Sub 926 (Sub 926) a revised DSDR-to-CVR conversion cost-benefit analysis that incorporates the cost of replacing any lost peak reduction capacity; and (3) file an updated report in the IRP docket and Sub 926 that estimates CVR’s anticipated capital and O&M costs, peak reduction, and energy savings for the next 10 years. DEP shall file this information by August 1, 2021. DEP shall bear all risk of disallowance of DSDR-to-CVR conversion costs if the cost-benefit analysis shows that conversion costs, including replacement peak reduction capacity, exceed benefits.

The Commission notes that DEP’s GIP is inconsistent as to its proposed treatment of new GIP-driven DSDR-related costs. While the CVR conversion costs are included in the deferral requested in this rate case, DEP apparently plans to recover other DSDR-related GIP costs in the Company’s DSM/EE rider. The Commission finds this bifurcated approach to cost recovery for CVR/DSDR to be potentially problematic. In addition, the Commission notes that fuel savings from CVR will flow to all customers via the fuel rider (as DSDR fuel savings do currently), while the bulk of costs for the legacy DSDR system are being recovered via DEP’s DSM/EE rider. Pursuant to N.C.G.S. § 62-133.9(f), industrial customers can avoid DSM/EE rider charges and hence would receive the additional fuel savings benefits of the CVR conversion without paying their share of a major portion of the related system costs. Due to this misalignment of costs and benefits the Commission will require DEP to file a proposal to move all DSDR and CVR costs into base rates when the Company files its next general rate case.

The Commission has carefully reviewed the evidence on DEP’s GIP proposal in this docket and concludes that acceptance of the Second Partial Stipulation’s provisions between the Public Staff with DEP related to the GIP programs is appropriate and is supported by material and substantial evidence of record.

The Commission’s acceptance of the GIP provisions of the Second Partial Stipulation is limited. The Commission’s decision simply allows DEP to treat costs incurred in pursuing the settled GIP programs as regulatory assets pending a prudence and reasonableness determination in a later rate case. DEP remains fully at risk for the reasonableness and prudence determination of its GIP costs and for their ultimate recovery from customers, as would be the case if DEP simply undertook these programs without a deferral and then sought recovery of the costs in a rate case. The only difference is that deferral of these costs allows certain between-rate-case earnings impacts of these costs to be held on the books of DEP as a regulatory asset and preserves them for possible future recovery if they are determined by the Commission, in a future proceeding, to be just and reasonable, prudently incurred, and otherwise eligible for recovery from customers.

The Commission concludes that the parties have compromised significantly to reach agreement, as evidenced by the Second Partial Stipulation, and deferral treatment for the GIP programs identified in the Second Partial Stipulation is reasonable and in the public interest. The Commission recognizes that the Company has undertaken stakeholder engagement efforts since the last rate case and made considerable efforts in this regard, as directed by the Commission. Through the stakeholder process, and continuing through this rate case proceeding, the Company has significantly narrowed its deferral request. The accounting deferral request, as modified by the Second Partial Stipulation with the Public Staff, and supported by other intervenor settlement agreements, represents a set of programs that can be classified as grid modernization, along with reporting requirements that will ensure collaboration and transparency as investments are made. The approval for deferral accounting treatment is limited to $400 million, which will incent DEP to manage its spending, and any amounts actually spent and deferred by the Company will be subject to review for reasonableness and prudence before any such costs are passed on to customers. Finally, the deferral accounting treatment approved in this proceeding shall be considered specific only to this case in light of the evidence of record in this proceeding and shall not be given any precedential value by the Commission regarding any future general rate case proceeding or deferral request or any other proceeding before the Commission at any point in the future.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 40

Regulatory Asset and Liability Rider

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Smith and Pirro, Public Staff witness Dorgan; and the entire record in this proceeding.

Summary of the Evidence

In the 2018 DEP Rate Order the Commission ordered that “if DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case."

DEP witness Smith testified that the Company has continued to record all revenue received for deferred amounts related to regulatory asset and liability accounts until the Company's next general rate case – this proceeding – in compliance with the Commission's directive. Tr. vol. 13, 134. The Company requested that customer rates be decreased by $2.1 million as a result of regulatory assets or liabilities that have been over-amortized since the last general rate case. *Id.* at 133. The Company proposed a Regulatory Asset and Liability rider (RAL-1) to return this balance to customers over a one-year period. *Id*. at 134. Smith Exhibit 5 shows the calculation of the resulting net over amortization balance.

Witness Pirro testified that a proposed uniform rate of $0.00005 per kWh for Rider RAL-1 is derived in Smith Exhibit 5 and will be effective for 12 months. Tr. vol. 11, 1112. He noted that the proposed Rider RAL-1 tariff is provided in the Company's proposed tariffs filed as Exhibit B to the Company's Application. *Id*.

Public Staff witness Dorgan testified in his direct testimony that the Public Staff had reviewed the Company's proposed Regulatory Asset and Liability Rider and agreed with the calculation. The rider was reflected in Public Staff witness Maness's Second Stipulation Exhibit 1, supporting the Second Partial Stipulation.

No other parties opposed or otherwise addressed the proposed Rider RAL-1.

Discussion and Conclusion

The Commission finds and concludes that the Company's proposed Regulatory Asset and Liability rider (RAL-1) is just and reasonable, consistent with the Commission's directive relating to the treatment of net over-amortizations of expired regulatory assets and liabilities since the Company's last base rate case and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41-48

Tax Act Issues

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations, and the CIGFUR Stipulation; the testimony and exhibits of DEP witnesses De May, Smith, Newlin, Panizza, Hager, and Hevert, Public Staff witnesses Dorgan and Hinton, CIGFUR witness Phillips, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness De May

Witness De May noted that the impacts of the federal Tax Cuts and Jobs Act of 2017 (Tax Act) have been incorporated into the Company's request, as outlined in the testimony of witnesses Smith and Panizza.

Witness Smith

Witness Smith described DEP's proposed changes to the existing EDIT-1 Rider[15] and the addition of a new EDIT-2 Rider to refund federal and state income tax related amounts owed to customers due to Tax Act and recent reductions to North Carolina state corporate income tax rates.

Witness Smith stated that in addition to increased revenue from tariff rates for electric service, the Company requests that customer rates be increased by $7.4 million, as presented in Smith Exhibit 3, through a revision in the existing North Carolina EDIT-1 Rider and decreased by $127.6 million, as presented in Smith Exhibit 4, through the proposed EDIT-2 Rider. Witness Smith maintains that the two EDIT riders represent amounts due from or owed to customers related to tax rate changes and EDIT, in addition to what is reflected in the proposed revenue increase in Smith Exhibit 1. Witness Smith maintained that Smith Exhibit 4 illustrates the EDIT-2 Rider to refund various categories of EDIT to customers, including federal EDIT, North Carolina EDIT related to the 2019 change in the tax rate from 3.00% to 2.50%, and the provisional revenues resulting from the Tax Act.

Witness Smith noted that the reduction as provided in the Tax Act became law on December 22, 2017. The Company began deferring the provisional revenues associated with this reduction in income tax rates starting January 1, 2018, through service rendered November 30, 2018, into a regulatory liability account. Witness Smith maintained that the Commission, in its order dated November 26, 2018, in Docket No. M-100, Sub 148, approved a base rate decrement proposed by the Company to pass through the tax benefits of the federal corporate income tax rate reduction. Witness Smith stated that, accordingly, the Company commenced passing through the revenue impacts of the reduction in the federal corporate income tax rate to customers starting December 1, 2018. She noted that this decrement is eliminated through the proposed rates in this proceeding, which reflect the new lower federal corporate income tax rate of 21.00%.

[15] EDIT-1 was established in Sub 1142 to flowback $42.577 million per year over a four-year period to reflect the reduction in the North Carolina corporate income tax rate. This flowback period was agreed to by DEP and the Public Staff and accepted by the Commission.

Witness Smith explained that DEP's proposed EDIT-2 Rider contains the following five categories of benefits for customers, as follows:

(1) Federal EDIT – protected;

(2) Federal EDIT – unprotected, Property, Plant, & Equipment (PP&E)-related;

(3) Federal EDIT – unprotected, non-PP&E-related;

(4) Deferred (provisional) revenue - federal income tax; and

(5) NC EDIT.

Federal EDIT - protected

Witness Smith explained that these amounts are generally related to PP&E and there are specific IRS requirements mandating that this amount be returned to customers no more quickly than as prescribed by the IRS. The amortization period the Company is using for Protected EDIT is called the Average Rate Assumption Method (ARAM) and results in a Year 1 amortization rate for this category of 3.70%. Also, as witness Panizza noted, protected amounts ultimately become unprotected over time. As such, the Company estimated this amount and captured this transition from the Protected to Unprotected category on Smith Exhibit 4, Page 1, Line 3.

Federal EDIT – unprotected-PP&E related

Witness Smith stated that these amounts are also related to PP&E but do not fall under the IRS guidelines for protected status. Because the Company would have paid these amounts to the IRS over the remaining life of the underlying property, the Company is proposing to return these amounts to customers over a 20-year period. As noted by witness Panizza, this approach balances the customer's and the Company's interests, minimizing customer rate volatility and addressing the Company's cash flow concerns.

Federal EDIT – unprotected non-PP&E related

Witness Smith stated that these amounts are not related to PP&E but are related to items such as regulatory assets and liabilities and other balance sheet items. The Company proposes to return these amounts to customers over a five-year period. In addition, the Company has included in this category amounts transitioning from the Protected category to Unprotected status. Like the EDIT that results from the reduction in the federal corporate income tax rate, there are EDIT balances that resulted from the reduction in the North Carolina corporate income tax rate.

Deferred (provisional) revenue – federal income tax

Witness Smith stated that as directed in Docket No. M-100, Sub 148, the Company began deferring, effective January 1, 2018, the impact on customer rates of the reduction in the federal corporate income tax rate from 35.00% to 21.00%. She stated that beginning December 1, 2018, a new rate decrement approved by the Commission in Docket No. M-100, Sub 148 reflects the lower federal corporate income tax rate. She asserted that after December 1, 2018, deferral amounts are related to continuing accrual of returns on the deferral balance. She noted that Smith Exhibit 4, Page 1, Line 8, shows the projected balance of this liability as of February 2020. Witness Smith maintained that the Company will continue to defer the impact from March 1, 2020, through the effective date of new rates in this case. She stated that those additional amounts are not being estimated now but will be included in the Year 2 EDIT-2 Rider calculation. Witness Smith stated that the Company is proposing to incorporate the refund of these provisional revenues in the EDIT-2 Rider proposed in this case, over a two-year period.

NC EDIT

Witness Smith testified that in the Company's last general rate case in Sub 1142, the Commission approved a four-year State EDIT Rider (EDIT-1 Rider) to return EDIT resulting from reductions in the state corporate income tax rate in prior years. The State EDIT-1 Rider currently in place does not include EDIT related to the reduction in North Carolina state corporate income tax rate from 3.00% to 2.50% effective January 1, 2019. The Company is proposing to incorporate the refund related to this reduction in the North Carolina state corporate income tax rate from 3.00% to 2.50% in the EDIT-2 Rider proposed in this case, over a five-year period.

Witness Smith further noted that the Company's proposed EDIT-2 Rider will include the annual amortization for each of these five categories of benefits. She stated that the North Carolina retail amounts can be seen on Smith Exhibit 4, Page 1, Columns A through E. Witness Smith maintained that since these EDIT amounts are a reduction in rate base, rate base will increase as these amounts are refunded to customers. She stated that, as such, the rider also calculates the adjustment to increase rate base resulting from the refund of EDIT to customers; this is shown in Smith Exhibit 4, Page 2, Column L. She noted that Column M shows the revenue requirement equal to the sum of the amortization and return; Column N shows the revenue requirement grossed up for the Commission's regulatory fee and uncollectible expense; and the amount in the Year 1 row on Smith Exhibit 4, Page 2 of $127.6 million decrease is the rider amount that is being proposed in this case.

Witness Smith explained that the Year 1 rider amounts are based on the balance of EDIT at December 31, 2018, as described by witness Panizza and are updated to reflect the expected balance at August 31, 2020, when the proposed rider is expected to be implemented. She stated that this projection will be further updated to reflect actual February 29, 2020, balances, as well as the latest ARAM rate, prior to the hearing.

Witness Smith maintained that years two through five are shown for illustrative purposes and that the actual rider amounts for those years may change based on several factors:

(1) additional adjustments to any of the balances on Rows 1 through 4 of Smith Exhibit 4;

(2) a change in the ARAM rate. Witness Smith detailed that the Company updates this rate annually and the most current rate must be used when establishing customer rates;

(3) future rate cases. Witness Smith maintained that in future rate cases, the EDIT balance in base rates shown in Column J and the rate of return used to calculate Column L of Smith Exhibit 4, Page 2 would be updated based on what is approved in that case; and

(4) the retention factor used to calculate Column N, which will be updated to reflect any future changes in the Commission's regulatory fee.

She stated that the Company proposes to file the rider amounts, along with the spread to the classes and derivation of the rate for each subsequent year, with the Commission annually in this docket by September 30, for rider rates effective December 1. Witness Smith maintained that the Year 1 EDIT-2 revenue requirement, shown in Smith Exhibit 4, was provided to witness Pirro who explains the derivation of the rider rate in his testimony. She noted that witness Hager explains how the amounts were allocated to the customer classes in her testimony.

Witness Smith filed supplemental direct testimony wherein she updated the EDIT calculation to reflect known changes to the EDIT balances and amortization amounts as of February 2020. She noted that she revised her Exhibit 4 to reflect the completion of Duke Energy's 2018 federal income tax return. She stated that the annual amortization percentage for federal protected EDIT has been updated to an actual amount that aligns with the most recently filed federal income tax return, which is the Company's best estimate for the following year's protected EDIT amortization. Witness Smith maintained that this update is necessary to comply with federal tax normalization rules and was referenced in her direct testimony. Witness Smith asserted that, additionally, the federal unprotected PP&E-related EDIT and State EDIT components of the rider were updated to reflect minor revisions to the EDIT amounts.

Witness Newlin

Witness Newlin testified about the impact of Tax Act on the Company's credit ratings. He stated that the rating agencies have identified several challenges the Company faces in maintaining its credit ratings, one of which is the reduced cash flow resulting from federal tax reform. Witness Newlin maintained that Moody's is particularly focused on downward pressure on financial metrics due to regulatory lag, including in the recovery of coal ash basin closure costs and storm expense. Moody's also points to federal tax reform putting pressure on the Company's credit metrics due to reduced cash flows.

Witness Newlin further noted that in January 2018, Moody's published a report outlining its initial assessment of the impact of tax reform on the regulated utility sector. Witness Newlin stated that in addition to outlining the negative impact of tax reform on utilities and the regulatory uncertainties related thereto, Moody's changed the rating outlook of 24 utilities (including Duke Energy Corporation) from "Stable" to "Negative." Witness Newlin noted that the January 2018 Report updated Moody's 2019 outlook for the regulated utility sector to "Negative" from "Stable." He stated that a key factor in this outlook change was a decline in cash flows – "the combination of a lower tax rate and the loss of bonus depreciation as a result of the [Tax Act] means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes on an ongoing basis." Of the 24 utilities Moody's placed on "Negative" outlook on January 16, 2018, Duke Energy was the first to have its outlook resolved. Witness Newlin noted that in August 2018, Moody's issued a credit opinion restoring Duke Energy's outlook to "Stable." He asserted that Moody's attributed this to an expectation that Duke Energy will maintain supportive regulatory relationships and highlighted credit supportive rate case outcomes across several regulatory jurisdictions.

Witness Newlin testified that, if unmitigated, the reduction in cash flows will erode DEP's credit metrics, citing a June 2018 Moody's report. Witness Newlin stated that certain factors that could lead to a downgrade including "[a] deterioration in the credit supportiveness or emergence of a more contentious regulatory relationship which negatively impacts cash flows or the timeliness of cost recovery, particularly with regards to coal ash remediation recovery in North Carolina." Moody's identifies "credit supportive regulatory relationships" as a credit strength and elaborates that "[t]he stable outlook reflects our expectation that [Duke Energy Corporation] will maintain supportive regulatory relationships in all of its jurisdictions."

Witness Newlin stated that deferred taxes are not large pools of money that the Company holds in an account somewhere; instead, they are collections that occur over time based on the life of the underlying assets, which the Company has used to invest in its business during the deferral period. Witness Newlin therefore argued that customers have benefitted because the Company has used these "zero interest" loans to finance its business rather than incurring financing costs that are passed on to customers. Witness Newlin argued that when the tax rate changes, either up or down, leveraging the over and undercollection of these funds in a proper and principled manner benefits both the Company and its customers. He maintained that if adjusting rates to account for tax changes is done in a haphazard manner, it can cause rate volatility and harm to customers as well as the financial health of the utility.

Witness Newlin also testified that if, for example, the Commission determines that refunds resulting from decreases in tax rates should be provided to customers as quickly as possible, then it logically follows that DEP would need to access the capital market to raise cash to provide for the shortfall in funds collected. Witness Newlin argued that this unplanned and possibly large capital raise could put stress on DEP's credit quality and rating. Were any future tax increases also collected from customers as quickly as possible Witness Newlin maintained that customers would then experience an immediate, perhaps dramatic, increase in rates, which the Commission attempts to avoid by way of gradualism. He argued that that same concept of gradualism should apply equally to tax decreases and must be considered just as it might with tax increases.

Witness Newlin noted that DEP has ADIT where it has collected a book level of tax expense for tax liabilities from customers. He stated that because the Internal Revenue Service (IRS) rules provide certain financial incentives, such as accelerated depreciation and credits, actual tax expense can be lower for tax purposes than book expense and create timing differences between when the costs are recovered from customers versus when the costs are payable to the government. Witness Newlin maintained that often IRS income is lower in the early years because the IRS commonly offers credits, accelerated depreciation, and other incentives so that the Company is collecting from customers at a level higher than what is actually being paid in cash taxes. Witness Newlin noted a liability to pay those taxes in the future is thus recorded to the Company's balance sheet because it is not a permanent reduction in taxes but rather a delay in payment of cash taxes. Witness Newlin maintained that a deferred tax liability is a customer benefit; it serves as a reduction to rate base and, because the Company does not earn on rate base to the extent that the Company has a deferred tax liability on the balance sheet, customers effectively save the weighted average cost of capital on the deferred tax balance.

Witness Newlin further noted that because of the change in the corporate income tax rate from 35.00% to 21.00%, the Company now has EDIT, which is excess ADIT that must be returned to customers where the Company previously collected from customers at the higher 35.00% tax rate and will now have a lower payment obligation at the new 21.00% tax rate. Witness Newlin maintained that had the federal corporate income tax rate not changed, thus creating EDIT, the average flowback of the property-related deferred taxes would have been 22 years. Thus, he testified that DEP proposes to flow these property-related EDIT back to customers over a 20-year period. Witness Newlin argued that an EDIT flowback period that more closely matches the life of the underlying asset smooths out the cash flow hit the Company would take as it returns EDIT to customers and lessens the need for the Company to raise those funds from investors and third-parties. Similarly, he asserted that, had the tax rate increased, the Company would not request to recover the increased amount instantly or over a short timeframe for the same reason – because the higher taxes would be paid over the life of the asset. Witness Newlin argued that addressing the impact on customer rates over a longer period also helps avoid rate volatility.

Witness Newlin provided examples of several other state utility commissions that have taken steps to mitigate the negative impacts of tax reform.

Witness Panizza

Witness Panizza noted that the Tax Act reduction in the corporate tax rate is accompanied by many other provisions having varying impacts on the revenue requirement, and that these impacts must be considered particularly as they relate to cash flow. He outlined several articles that supported his testimony.

Witness Panizza stated that DEP's $1,177 million (or $1.2 billion) of EDIT, as of the end of 2018, falls into three different buckets. Witness Panizza stated that the first bucket contains approximately $823 million is what is called protected EDIT – that is, EDIT related to the Company's investment in PP&E, whose flowback treatment is expressly made subject to IRS normalization rules by the Tax Act. He noted that the normalization rules of the Tax Act require protected EDIT to be flowed back over the remaining lives of the property giving rise to the deferred tax balance. He also noted that the remaining two buckets of EDIT, totaling approximately $354 million as of the end of 2018, is unprotected under IRS rules, and, therefore, subject to flowback in a timeframe subject to the Commission's discretion.

Witness Panizza stated that the second bucket, and the lion's share of unprotected EDIT, totaling approximately $327 million of the $354 million, still relates to the Company's investment in PP&E. Thus, he maintained that this portion of unprotected EDIT is not required to be normalized under the Tax Act. Witness Panizza stated that although both buckets are property related, the Internal Revenue Code protects one but not the other. However, witness Panizza argued that the rationale for normalization should apply to this portion of EDIT as much as it applies to protected EDIT. He noted that the assets represented in this bucket have an average life of approximately ten years for DEP, although the Company's proposal uses a shorter 20-year period over which to accomplish this flowback.

Witness Panizza stated that the third and final bucket, totaling approximately $27 million as of the end of 2018, is non-PP&E-related, unprotected EDIT, and mostly consists of the EDIT that transitioned from protected to unprotected during 2018. Witness Panizza maintained that these balances are as of the end of 2018; the Company has made and may make additional adjustments to these amounts in 2019, as protected amounts ultimately become unprotected over time.

Witness Panizza argued that the Company's proposal included in this case provides immediate benefit from the Tax Act and continues benefitting customers through the return of deferred taxes over time. He concluded that the Company's proposal further complies with accounting requirements while preserving the Company's credit rating by not creating undue pressure on cash flows.

Witness Hager

Witness Hager stated that the Company has allocated the benefits in the EDIT-2 Rider to the classes based on the accumulated deferred income taxes (ADIT) allocator.

She stated that she has reviewed this allocation and finds that it is reasonable based on cost causation principles. Witness Hager maintains that since the EDIT amounts were previously part of ADIT as explained by DEP witnesses Smith and Panizza, this is consistent with how the amounts were allocated prior to the federal corporate income tax rate change and reasonably reflect how the benefits were created.

CIGFUR Testimony

Witness Phillips stated that DEP should be ordered to return EDIT to its customers as soon as possible. He stated that he has reviewed DEP's proposal to refund EDIT to its customers and that, in his opinion, the Commission should use its discretion to require DEP to refund the federal unprotected EDIT as expediently as possible to the ratepayers. Witness Phillips recommended that the Commission reject DEP's proposal to refund the federal unprotected PP&E-related EDIT over a prolonged period.

CUCA Testimony

Witness O'Donnell stated that EDIT are taxes that consumers have paid to the utility in prior years that were planned to be paid to the taxing authority in future years. He maintained that EDIT is essentially a product of the tax difference between accelerated depreciation and straight-line depreciation. Witness O'Donnell noted that in ratemaking, taxes are calculated using straight-line depreciation and that the utility uses accelerated depreciation to calculate its taxes. He argued that therefore the utility pays lower taxes than is the case with straight-line deprecation used for ratemaking purposes. Witness O'Donnell maintained that as an asset ages, the taxes that the Company collected but did not pay to the government are eventually paid so that the net result, over time, is the consumer pays the tax owed by the utility.

Witness O'Donnell noted that when the federal government reduced the corporate income tax rate from 35.00% to 21.00% in 2017, EDIT was created on DEP's books. He stated that as a result the EDIT funds need to be returned to their rightful owner, the North Carolina retail customers of DEP. Witness O'Donnell further noted that the rate increases sought by DEP in this rate case are significantly lower when the return of EDIT is considered.

Public Staff Testimony

Witness Dorgan

Witness Dorgan testified that DEP did not adjust to exclude any EDIT from rate base but instead proposed to handle each of the five categories in a single rider, with rate changes occurring each year based on the proposed amortizations for these categories, which range from five years to 39.6 years. Witness Dorgan maintained that the five categories of refunds should be handled separately due to the differing natures of the amounts and the amortization periods. He asserted that this provided a more transparent means of tracking the Tax Act and North Carolina tax-related refunds to customers for each year. Therefore, witness Dorgan made several recommendations regarding federal EDIT.

First, witness Dorgan recommended an adjustment to remove the federal protected EDIT from the EDIT-2 Rider proposed by DEP and instead leave that amount in rate base. He proposed to amortize the federal protected EDIT over 39.6 years in base rates and to remove the first year of amortization from the deferral amount for purposes of this proceeding.

Next, for federal unprotected EDIT, witness Dorgan stated that tax normalization rules are very clear and that EDIT is either protected or not. He maintained that the Company's assertion, that it should only return unprotected PP&E-related EDIT over the same period of time it would have paid the funds to the IRS had the Tax Act not been passed, is not supportable by any logical accounting or ratemaking principle. Witness Dorgan recommended removing the EDIT regulatory liability associated with all the unprotected differences from rate base and placing it in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs. Witness Dorgan noted that the immediate removal of federal unprotected EDIT from rate base increases the Company's rate base and mitigates regulatory lag that might occur from refunds of federal unprotected EDIT not contemporaneously reflected in rate base. He argued that refunding the federal unprotected EDIT over five years allows the Company to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time.

Witness Dorgan stated that for the provisional revenues collected since the federal corporate income tax rate decreased from 35.00% to 21.00% he recommended placing that amount in a separate levelized rider, to be amortized over a one-year period. He also removed the balance from the working capital schedules since he recommended a refund over one year. Witness Dorgan maintained that a one-year amortization period is consistent with the period approved by the Commission in the most recent rate cases of Aqua North Carolina, Inc.; Carolina Water Service, Inc. of North Carolina; and Piedmont Natural Gas Company.

Finally, witness Dorgan proposed that the State EDIT amount be removed from rate base and placed in a separate rider to be returned over one year with a return on the balance. He noted that this period is consistent with the Commission's Order in Dominion Energy North Carolina, Docket No. E-22, Sub 532.

Witness Dorgan noted in his supplemental direct testimony that he updated the amount of each EDIT category to reflect the amounts on Smith Supplemental Exhibit 4, Line 8 that was filed on March 13, 2020.

Witness Hinton

Witness Hinton provided testimony on how the Public Staff's proposals impact DEP's credit metrics. He noted that DEP provided the Public Staff with the projected credit metrics, specifically the Cash Funds from Operations over Total Debt (FFO/Debt) under both the Public Staff's proposed five-year flowback proposal and DEP's proposed 20-year flowback proposal for federal unprotected EDIT. Witness Hinton asserted that the shorter time allowed to return the unprotected EDIT to customers results in lower credit metrics for the forecast period of 2020 through 2023.

Witness Hinton maintained that the 20-year flowback of unprotected EDIT results in a higher average projected FFO/Debt ratio of approximately 40 basis points. Witness Hinton noted that as outlined in Moody's March 28, 2019 Credit Opinion, a FFO/Debt ratio that is between 21.00% and 23.00% qualifies for an "A" rating. Witness Hinton stated that given that the predicted FFO/Debt metric with a five-year flowback is below 21.00% in only one year, 2020, and the other metrics are 22.00% and 24.00% through 2023, he believed that unexpected financial developments such as significant reductions in DEP's cash flows or significant increases in its debt balances would have to occur in order to trigger a ratings downgrade.

Witness Hinton also noted that Moody's places 40% weight on financial strength as measured by its quantitative financial metric, 50% weight on the regulatory climate, and 10% weight on utility diversification. He stated that the 50% weight on regulation focuses on two areas: the regulatory framework and the ability to recover costs and earn returns. Witness Hinton maintained that the regulatory framework relates to rate setting by the governing body, credit supportive legislation that is responsive to the needs of the utility, and the way the utility manages the political and regulatory process. Witness Hinton stated that the ability to recover costs and earn returns on its investments relates to the assurance that the regulated rates will be based on prescribed and clear ratemaking methods. Witness Hinton asserted that, while awarding the least weight in its rating methodology to diversification, Moody's positively views utilities with multinational and regional diversity in terms of regulatory regimes and diversity in the economics of its service territories.

Witness Hinton further maintained that DEP has other means to finance the EDIT flowback over a five-year period that would not adversely affect its FFO/Debt metrics. He noted that the filed E-1, Item 38 contains DEP's financial forecast, which indicates that DEP projects being financed with 48% long-term debt and 52% common equity every year through 2023. Witness Hinton stated that from 2020 through 2023, Item 38 indicates that DEP plans to issue a total of $3.45 billion in long-term debt and infuse $2.83 billion to Duke Energy Corporation (parent). Witness Hinton argued that this indicated that an option may exist for DEP to offset some of its debt issuances through a reduction in its planned contributions to its parent, which would better allow the Company to maintain its Moody's A2 credit rating or, in the event of a downgrade, the ability to restore its current credit rating. Witness Hinton noted that DEP witnesses De May and Newlin stressed the importance of maintaining DEP's credit quality, which Moody's places as the second highest rated among Duke Energy Corporation and its other six electric utility subsidiaries as follows:

Moody's Credit Ratings

	Long-Term Issuer Rating	First Mortgage Bonds
Duke Energy Carolinas	A1	Aa2
Duke Energy Progress	A2	Aa3
Duke Energy Indiana	A2	Aa3
Duke Energy Florida	A3	A1
Duke Energy Ohio	Baa1	A2
Duke Energy Kentucky	Baa1	N/A
Duke Energy Corporation	Baa1	N/A

Witness Hinton also noted that Duke Energy Corporation announced that it would issue approximately 29 million shares of common stock which will result in approximately $2.5 billion of net proceeds. He argued that this additional equity could allow DEP to decrease its projected equity infusions to the parent Company, alleviating the need to issue as much new debt and reducing the possibility of a downgrade.

Witness Hinton stated that DEP expects that a one-notch downgrade by Moody's to A3 would increase the investor-required bond yield by 10-basis points. He stated that DEP maintains that this estimate was based on market conditions associated with a normal or typical period in the bond market and, when considering the burden associated with DEP's long-term debt, it was worth noting that Moody's A-rated long-term utility bond yields as of February 29, 2020, are 3.11%, the lowest in over 30 years. He argued that in view of DEP's financial forecast, he believed that the added cost of debt capital from a downgrade to an A3 rating will not be burdensome on the Company and its customers. Witness Hinton further noted that since 1975 DEP has had five upgrades and three downgrades and that it does not appear that any downgrade resulted from the 1986 change in the federal corporate income tax rate.

Witness Hinton concluded that based on his review of the FFO/Debt credit metrics, it is unlikely that spreading the refund of EDIT over five years will result in a debt rating downgrade and that a five-year flowback as recommended by the Public Staff is reasonable and fair to DEP's ratepayers and DEP.

Finally, witness Hinton stated that he would expect that regulatory lag would be effectively removed by the cash payment to compensate DEP for its storm costs of approximately $668,140,000 (DEP's storm costs as of January 31, 2020). Witness Hinton argued that credit rating agencies positively view securitization of utility costs with the prompt and certain recovery from the net proceeds from the sale of the bonds. Witness Hinton therefore asserted that the securitization of the Company's storm costs should ameliorate some of the downward pressure on the Company's credit metrics.

DEP Rebuttal Testimony

Witness De May

Witness De May contested many of the recommendations set forth by the Public Staff and other intervenors in their direct testimony, asserting that if adopted by the Commission they would negatively affect the Company's financial ability to make necessary investments and help the State achieve its desired energy future. Witness De May also testified that many of the intervenors' positions are contrary to established regulatory rules and precedent, including precedent established as recently as the Company's 2018 Rate Case in Sub 1142.

Witness Hevert

Witness Hevert noted that the March 2015 Report by Moody's mentioned in witness Woolridge's testimony makes clear that utilities' cash flows have benefited from increased deferred taxes, which themselves were due to bonus depreciation. Witness Hevert noted that Moody's recognized that the rise in deferred taxes eventually would reverse. Witness Hevert stated that in January 2018 Moody's spoke to the effect of that reversal on utility credit profiles in the context of tax reform:

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.

Witness Hevert noted that Moody's June 2018 changed its outlook on the U.S. regulated sector to "negative" from "stable." Witness D'Ascendis adopted this testimony as his own.

Witness Newlin

Witness Newlin disagreed with Public Staff witness Hinton's recommendation for returning PP&E-related unprotected EDIT over a five-year period. Witness Newlin maintained that witness Hinton did not consider the longer-term benefits to customers of a longer flowback period. Witness Newlin stated that while customers should, and ultimately will, benefit from the overall reduction in the revenue requirement the Commission should also consider other impacts of the Tax Act, particularly as it relates to cash flow.

Witness Newlin argued that an accelerated return of EDIT over an arbitrary five-year period would adversely impact the Company's cash flow to fund ongoing operations and new infrastructure investments. He stated that an unmitigated cash flow shortfall could force the Company to rely excessively on third-party capital to fund itself, to the ultimate detriment of its financial condition. Witness Newlin noted that in Public Staff witness Hinton Exhibits 1 and 2, witness Hinton uses seven years of FFO/Debt metrics (2017 to 2019 based on historical data and 2020-2023 based on projected data as provided by the Company) and focused on a three year moving average to determine a 40 basis point degradation in FFO to Debt based on a five-year flowback as compared to the flowback as proposed by the Company in this rate case (a 20-year period for PP&E-related EDIT and a five-year flowback for non-PP&E EDIT). He stated that while Moody's presents a three-year trend in its credit opinions, credit metrics are a snapshot of an issuer's potential default risk at a point in time, and there is an inherent emphasis on forward-looking metrics when providing credit opinions, as the overall rating represents the risk of default on a prospective basis. Witness Newlin noted that as summarized in Hinton Exhibits 1 and 2, individual periods are impacted by as much as 50 basis points over the five-year period. He stated that, furthermore, this analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other potentially credit negative proposals by the Public Staff.

Witness Newlin responded to witness Hinton's suggestion that the Company should moderate upstream equity dividends to Duke to alleviate potential credit pressures resulting from accelerated EDIT flowback. He stated that Duke has a long-term targeted dividend payout ratio of 65-75% and subsidiaries can be expected to contribute at a similar level over the long-term. Witness Newlin noted that DEP's average payout ratio over the last three years has been approximately 15%, well below this threshold, to facilitate its ongoing capital plans, large expenditures related to coal ash remediation, and investments to better serve its customers. Witness Newlin stated that, for example, during 2019, DEP did not provide any dividend to the parent, its lowest contribution in the last four years.

Witness Newlin also responded to witness Hinton's suggestion that Duke can use funds from its $2.5 billion November common equity issuance to allow DEP to further decrease equity infusions to the parent. Witness Newlin noted that the equity issuance was intended to protect Duke's credit in light of a range of scenarios related to the delay and regulatory uncertainty around the Atlantic Coast Pipeline, a key infrastructure project. Witness Newlin stated that preserving the credit quality of DEP's parent is likewise important to DEP because S&P uses a family rating methodology and weakness in the parent could lead to a lower credit opinion for the entire family of rated entities.

Witness Pirro

In his second supplemental testimony witness Pirro explained that he had revised the EDIT Rider pursuant to the CIGFUR Settlement to refund EDIT on a uniform cents per kWh basis. In his joint supplemental rebuttal testimony witness Pirro noted that returning EDIT as proposed in the CIGFUR Settlement balances out the subsidization of the residential class by nonresidential rate classes and is consistent with the rate design in the Company's last rate case.

Witness Smith

Witness Smith stated that DEP does not oppose rider treatment for EDIT but opposes the specific rider treatment as proposed by the Public Staff. The Company continues to believe that its proposed EDIT Rider is a fair balancing of relevant issues. Witness Smith disagreed with witness Dorgan that the EDIT funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible. Witness Smith also contested witness Dorgan statement that the Company's proposal is not supportable by any logical accounting or ratemaking principle.

Witness Smith further addressed witness Dorgan's testimony that refunding the unprotected EDIT over five years allows the Company to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time. She stated that the Public Staff has provided the Company with the benefit of removing the total amount of the unprotected EDIT credit from rate base in the current case, thus providing the Company with an increase in rates to moderate any cash flow issues. Witness Smith maintained that the financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Witness Smith also argued that the Public Staff's recommendation on amortization periods tends to be asymmetrical. Witness Smith stated that DEP continues to oppose this asymmetrical treatment, especially given the cash flow concerns raised by Company witness Newlin in his rebuttal testimony.

Stipulations

Public First and Second Partial Stipulations

In Section III.18 of the First Partial Stipulation DEP and the Public Staff agreed to remove the protected federal EDIT from DEP's proposed EDIT Rider and return these amounts to customers through base rates.

In Sections III.A.(2)-(5) of the Second Partial Stipulation DEP and the Public Staff agreed as follows:

> Total unprotected federal EDIT, North Carolina EDIT, and deferred revenues related to the provisional overcollection of federal income taxes (or the deferred revenues) will be returned to customers through a rider by using a levelized rider calculation methodology as described and set forth in the testimony and exhibits of the Public Staff and will be amortized over a period of five years for total unprotected EDIT and two years for North Carolina EDIT and deferred revenues.

DEP and the Public Staff also reached agreement concerning how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate which may occur during the respective amortization periods as provided in detail in Sections III.A.(6)-(15) of the Second Partial Stipulation.

CIGFUR Stipulation

In Section IV of the CIGFUR Stipulation CIGFUR and DEP agreed that unprotected EDIT and the provisional revenues should be refunded to customers on a uniform cents per kWh basis.

Discussion and Conclusion on Return of Tax Act Items to Ratepayers

DEP and the Public Staff have stipulated on the appropriate treatment of the tax issues, as follows:

Tax Act Item	Stipulated Treatment
Protected federal EDIT	Remove from rider and amortize in base rates based on the IRS normalization rules
All unprotected federal EDIT	Levelized rider over five years
Provisional Revenues	Levelized rider over two years
State EDIT	Levelized rider over two years

DEP and the Public Staff also agreed how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate that may occur during the respective amortization periods, as provided in detail in Sections III.A.(6)-(15) of the Second Partial Stipulation. No intervenor offered any evidence or testimony opposing the EDIT provisions of the Public Staff Partial Stipulations.

The AGO argued in its post-hearing brief that DEP should promptly return to ratepayers over $400 million in EDIT and other overcollected taxes, either as a full offset to a rate increase or as a decrease in rates. The AGO argued that these amounts should be returned to customers as soon as possible to help North Carolinians deal with challenging economic conditions. The AGO also stated that DEP has already had the full use of the funds for almost three years since the enactment of the Tax Act, which has provided considerable time for DEP to prepare for the impact of the EDIT repayment on its cash flow. The AGO further noted that reductions in federal and state corporate income tax rates have lowered operating expenses for utilities and urged the Commission to require DEP to return all of the amounts to ratepayers over no more than two years.

Based upon the record of evidence in this proceeding, the Commission gives significant weight to the First and Second Partial Stipulations concerning the tax issues in this case and finds that it is appropriate to approve those portions of the stipulations. The Commission notes that no intervenor presented testimony disagreeing with the provisions of the settlements in this regard, although the AGO contended in its post-hearing brief that federal unprotected EDIT should be returned within two years instead of five years. However, the Commission is not persuaded that it is appropriate to reject the settlements on this point based on the overall benefits of settling these matters.

Further, the Commission credits the testimony of DEC witness McManeus who testified that while the Company has been able to use amounts relating to EDIT until they are flowed back through rates, customers are benefitted in the meantime:

> Because EDIT is reducing rate base, it's reducing current rates. The Company has use of the money, as you indicate on this chart, and customers are held harmless of the Commission's decision to push this forward to a future rate case.

Consolidated Tr. vol. 4, 82. Witness McManeus further explained:

> But we've talked previously about how deferred income taxes are a source of cash to the Company and, you know, they are an interest-free source of cash. And so when we collect monies in advance of paying to the IRS, then we are able to invest that money in our business and avoid the financing . . . costs. And that is all reflected in the Company's rates.

Id. at 86; *see also id.* at 87-88.

The Commission concludes that the amortization periods as stipulated appropriately balance the interests of the ratepayers and DEP. Therefore, the Commission finds it appropriate to approve the First and Second Partial Stipulations on the tax issues in their entirety. In addition, the Commission finds and concludes that the Company's proposed revision to the approved EDIT-1 rider to reflect the change in the federal corporate income tax rate from 35% to 21%, which was supported by witness Smith and not disputed by any party, is just and reasonable and should be approved.

Discussion and Conclusion on Allocation of EDIT and the Provisional Revenues

Under Section IV of the CIGFUR Stipulation CIGFUR and DEP agreed to the refund of unprotected EDIT and the provisional revenues on a uniform cents per kWh basis. In his direct testimony DEP witness Pirro stated that the rate class revenue requirement was allocated to each rate class using the factors appropriate for Accumulated Deferred Income Taxes and divided by test year retail billed sales for each rate class to establish the year 1 credit rates. Witness Pirro stated that the derivation of the credit rate applicable to each rate class is provided on Pirro Exhibit 8 and the proposed Rider EDIT-2 tariff is provided in the Company's proposed tariffs filed as Application Exhibit B.

CIGFUR argued in its post-hearing brief that by approving the uniform cents-per-kilowatt hour refund of EDIT to customers as agreed to in the CIGFUR Stipulation the different customer classes are moved closer to parity with the actual costs to serve each class. CIGFUR argued that this position was supported by DEP witness Pirro, who testified that residential customers have historically been subsidized by other customer classes and that the proposed rate design of the EDIT Rider helps offset this subsidy. CIGFUR further argued that witness Phillips supported the positions taken by

DEP witness Pirro, agreeing that the proposed rate design of the EDIT Rider reduces subsidies uniformly by 25% and moves rates closer to cost for all customer classes. CIGFUR also argued that DEP has in the past refunded unprotected EDIT to customers using this same levelized and uniform cents per kWh method. CIGFUR stated that no party has presented a compelling reason to depart from past practice.

The Public Staff argued that it is inappropriate to refund unprotected EDIT and deferred revenue giveback overpaid by customers through the EDIT rider on a uniform cents per kWh basis rather than as a levelized EDIT credit by specific customer-class divided by each class' adjusted test year sales. The Public Staff argued that in the DEC hearing witness Pirro testified that under this method one factor would be used for all customers, with the OPT-V class receiving a larger EDIT credit than it paid in EDIT. Further, the Public Staff noted that witness Pirro admitted that base rates and EDIT should be considered separately. The Public Staff maintained that CIGFUR witness Phillips also agreed that paying EDIT on the uniform cents per kWh basis would reduce any subsidies among classes and stated his belief that it was also done in this manner in the last DEP case. The Public Staff noted that its witness Floyd advocated for using witness Pirro's original methodology that returned the EDIT to classes based on how much each class had paid. The Public Staff contended that witness Floyd testified that under the CIGFUR Settlement, approximately $30 million would be shifted from the residential, small general service, and lighting customer classes to the medium and large general service classes. Further, the Public Staff stated that witness Floyd testified that since it is possible to quantify the amount of EDIT paid by each class, it is appropriate to return that amount to the class. As a result, the Public Staff recommended that the Commission not adopt this provision of the CIGFUR Settlement because it is unreasonable and not in the public interest in this case.

Based on the entire record in this proceeding the Commission declines to adopt Section IV of the CIGFUR Stipulation because it will not achieve just and reasonable rates and therefore is not in the public interest. As the substantial evidence shows EDIT results from the overpayment of taxes by customers paying rates that include, as a portion of the rate, charges to cover the utility's anticipated federal and state income taxes. In addition, the amount of those overpayments is determinable from the Company's books and records of customer billing revenues. While different customer classes may have different rates of return (ROR), these RORs are highly dependent on the cost of service allocation methodology utilized, as well as the time period during which the cost of service study was conducted. As such, subsidy/excess issues should be resolved on the basis of equity between customer classes and their relationship to the overall ROR, not by favoring one class of customers by returning to them more than they paid in EDIT.

While in prior rate cases for DEC and DEP use of a uniform EDIT rate to allocate state EDIT[16] was agreed to as part of a settlement, no party contested the issue in those

[16] In DEC's last rate case (Sub 1146), federal EDIT was deferred until the next rate case or three years, whichever was sooner. In DEP's last rate case (Sub 1142), federal EDIT was not addressed because DEP filed its rate case before the Tax Act was signed into law in December 2017 (and effective January 1, 2018; DEP rate case Order in Sub 1142 was issued on February 23, 2018).

cases and the Commission accepted the settlement terms on state EDIT without making detailed findings of fact as to the appropriateness of a uniform rate. However, in the Commission's recent order in Docket No. E-22, Sub 562, of which the Commission has taken judicial notice in this proceeding, the Commission approved the provision of the stipulation between Dominion Energy North Carolina (DENC) and the Public Staff that the EDIT Rider credit should be allocated to customer classes based upon North Carolina basic (non-fuel) rate revenue annualized reflecting current rates for 2018. Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, *Application of Virginia Electric and Power Co., d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, No. E-22, Sub 562, at 60-63 (N.C.U.C. Feb. 24, 2020), *appeal docketed*, No. 477A20 (N.C. Nov. 16, 2020).

With this issue now squarely before the Commission, the Commission finds it inappropriate to address any subsidy issues through reassignment of EDIT. The Commission gives substantial weight to the testimony of Public Staff witness Floyd that returning EDIT credits by customer class is a more equitable method by which to return EDIT. Thus, the Commission concludes that in this case it is inappropriate to refund the unprotected EDIT and provisional revenues to customers through the EDIT rider on a uniform cents per kWh basis and that rather these items should be refunded as a levelized EDIT credit by specific customer-class divided by the adjusted class test year sales.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-50

Cost Allocation Methodology

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation and CIGFUR Stipulation; the testimony and exhibits of DEP witnesses Hager and Pirro, Public Staff witness McLawhorn and Floyd, CIGFUR witness Phillips, and NCJC et al. witness Wallach; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

DEP witness Janice Hager testified that the purpose of the cost-of-service study is to align the total costs incurred with jurisdictions and customer classes responsible for the costs, and that cost causation is a key component in determining the appropriate assignment of revenues, expenses, and rate base among jurisdictions and customer classes. Witness Hager testified that costs are classified according to their cost-causation characteristics, and that these characteristics are typically defined as demand-related, energy-related, or customer-related. The cost-of-service study (COSS) supporting the Company's proposed rate design in this proceeding allocates the demand-related production and transmission costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak (SCP) cost allocation methodology.

Witness Hager testified that distribution costs are classified as either demand-related or customer-related. Witness Hager summarized different methodologies for determining the customer-related component of distribution costs. DEP incorporated the concept of “Minimum System” into its COSS for allocating costs to customers. Witness Hager testified that this is appropriate for allocation of customer-related distribution costs. After the Company determines the customer-related costs using the Minimum System Method (MSM), the remainder of distribution costs are classified as demand-related and are allocated based on Non-Coincident Peak (NCP) Demand.

Witness Hager further testified to DEP’s use of the MSM and stated that every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer caused DEP to install some amount of the distribution assets. According to witness Hager the concept DEP used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb).

Witness Hager stated that the reason NCP is used for allocating demand-related distribution costs is that distribution facilities serve individual neighborhoods, rural areas, and commercial districts. They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Witness Hager stated that contribution to NCP is the appropriate measure of determining customers’ responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

Witness Hager testified that all costs must be allocated to the appropriate jurisdiction and customer class. If any costs are omitted or remain unallocated then the utility’s rates will not allow for full recovery of the Company’s operating expenses, including its approved cost of capital. Further, she testified that once all costs and revenues are assigned, the COSS identifies the return on investment the Company has earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Company an opportunity to recover its costs and earn its allowed rate of return.

DEP witness Pirro testified that the base rate increase has been allocated to the rate classes on the basis of rate base. According to witness Pirro this allocation methodology distributes the increase equitably to the classes while gradually moving each class’s deficiency or surplus contribution to return to the retail average rate of return, within a band of reasonableness of +/- 10 percent, if possible.

Public Staff Testimony

The Public Staff recommended using Summer/Winter Peak & Average (SWPA) instead of SCP. Public Staff McLawhorn testified that SWPA more accurately and fairly reflects the planning and operation of DEP's production plant to meet the energy needs of its customers.

The Commission ordered the Public Staff to file testimony addressing at a minimum SCP, Winter Coincident Peak (WCP) and SWPA cost of service methodologies. Witness McLawhorn's testimony included an analysis of the impact of these cost-of-service methodologies across each of the retail classes of customers. Witness McLawhorn's discussion includes a comparison of class revenue increases for three of the methodologies (SCP, WCP, and SWPA). Further, the Public Staff provided some analysis of the Summer/Winter Coincident Peak (SWCP), Four Coincident Peak (4CP), and Twelve Coincident Peak (12CP) methodologies.

Public Staff witness Floyd testified that the Public Staff believes that assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR as determined by the COSS, and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

(1) Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;

(2) Maintain a +/-10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;

(3) Move each customer class toward parity with the overall jurisdictional ROR; and

(4) Minimize subsidization of customer classes by other customer classes.

Witness Floyd testified that the Company's assignment of its proposed revenue increase does not fully adhere to the Public Staff's recommended principles outlined above. Further, witness Floyd noted that the Public Staff intends to update its recommended jurisdictional revenue requirement and file supplemental testimony to provide a final recommendation on its recommended revenue change. Witness Floyd stated that he will provide the Public Staff's assignment of proposed revenue change at that time.

In his supplemental testimony witness Floyd presented the Public Staff's recommended distribution of revenues based on the results of the SCP, WCP, and SWPA cost-of-service methodologies and including the Public Staff's adjustments to the Company's revenue request. The assignment of the Public Staff's recommended revenue change was developed using the four basic revenue assignment principles outlined in witness Floyd's direct testimony. The Public Staff's proposed assignment adheres to each of these principles. Witness Floyd stated that his supplemental testimony provides an illustration of how base revenues and EDIT-2 credit should be assigned using the SCP and WCP cost-of-service methodologies; however, the Public Staff continues to believe that the SWPA is the most appropriate methodology for this case.

CIGFUR Testimony

CIGFUR witness Phillips recommended using WCP to reflect the fact that DEP now plans its generating system based on its winter peak demand. Witness Phillips stated that it is appropriate to classify all production investment as demand related. He argued that the capital costs are not a function of the number of kWh generated but are fixed and therefore are properly related to system demands, not to kWh sold. Witness Phillips stated that these costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are related to the existence of the property and not to the number of kWh sold. According to witness Phillips, if sales volumes change, these costs are not affected, but continue to be incurred, making them fixed or demand-related in nature. He concluded that investment in generation plant is properly classified as a demand-related cost.

Further, witness Phillips argued that if an attempt were made to increase the allocation of investment to one group of customers, on the theory that those customers benefit more than others from the lower energy costs that result from the operation of a base load plant as opposed to a peaking plant, as done in the SWPA method, the analysis should be carried to its logical conclusion. The logical conclusion, according to witness Phillips, would be to fairly and symmetrically allocate energy costs to the group of customers who are forced to bear the higher capital costs allocated to them on a kWh basis. Witness Phillips stated that energy costs allocated to the high load factor class should recognize lower operating costs which result from the higher capital costs of the base load plants. Finally, he stated that the SWPA method fails to allocate lower than average fuel costs to the high load factor customers.

CIGFUR witness Phillips testified that he agrees with DEP's COSS with respect to the allocation of certain distribution facilities. According to witness Phillips the Public Staff concluded in its March 2019 report that the use of the MSM for classifying and allocating distribution costs is reasonable.

NCJC et al. Testimony

Witness Wallach testified that the Company's COSS misallocates distribution costs partly by misclassifying a portion of such costs as customer-related by relying on a flawed minimum system analysis. Witness Wallach testified that the Company's COSS allocates more distribution plant costs to the residential rate classes than is appropriate under generally accepted cost causation principles. Further, witness Wallach suggested that the Commission should direct DEP to discontinue its use of the MSM and instead rely on the "basic customer method."

In its 2018 DEC Rate Order, the Commission ordered the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. The Public Staff submitted its report on March 28, 2019, in Docket No. E-100, Sub 162. In its report, the Public Staff concluded that use of the MSM by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge.

The basic customer method referenced by witness Wallach accounts for meters, service drops, and certain other related costs. These typically would not include transformer or wires costs. Witness Wallach referred to a report produced by the Regulatory Assistance Project (RAP) entitled *Electric Cost Allocation for a New Era*. The report states that "[t]he basic customer method for classification is by far the most equitable solution for the vast majority of utilities."

After the Company determines the customer-related costs using the MSM the remainder of distribution costs are classified as demand-related and are allocated based on NCP Demand. Witness Wallach recommended that the Commission reject the Company's use of the NCP Demand allocator to allocate distribution costs. According to witness Wallach the NCP allocator fails to accurately reflect usage patterns of residential customers and causes distribution costs to be over-allocated to the residential classes. Witness Wallach stated that to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution costs should be allocated to rate classes on the basis of each class' diversified peak demand.

CUCA Testimony

CUCA witness O'Donnell recommended that the Commission use the same cost allocation method approved by the Commission in the Company's last fuel case, which was an equal percentage change for all customer classes. He noted that in times of fuel cost increases this allocation methodology has benefited large consumers, and in times of fuel cost decreases this allocation methodology has benefited small consumers. Witness O'Donnell concluded that what has been deemed appropriate for fuel cases for many years should also be appropriate for the allocation of coal ash costs.

DEP Rebuttal Testimony

Witness Hager discussed some of the reasons DEP support the SCP methodology:

(1) The application of the summer peak load to allocate demand-related production and transmission costs is consistent with the Single Coincident Peak Method identified in the NARUC Electric Utility Costs Allocation Manual;

(2) The predominance of the summer peak in DEP's service territory;

(3) The historical significance of the summer peak in DEP's expansion planning such that the majority of DEP's embedded generation fleet was built in response to summer peaks, thus making it appropriate to allocate these historically incurred costs;

(4) The benefit of a cost allocation methodology that encourages the shifting of usage to off-peak times;

(5) The value of sending consistent pricing signals by using a method that has been approved by this Commission for many years; and

(6) The importance of a consistent cost allocation methodology among DEP's jurisdictions so that the Company does not under or over-recover its costs.

Further, witness Hager noted that she does not agree with witness McLawhorn's assertion that the SCP methodology only addresses the peak requirement of the capacity expansion planning process and places no value on the plants' requirement to produce energy at any time other than the peak hour. Witness Hager stated that this is not the complete picture. She explained that in developing a COSS, production costs are classified into demand and energy related costs. According to witness Hager, plant capacity is considered fixed to meet demand and therefore, the cost of plant capacity was assigned to customers on the basis of their contribution to the summer coincident peak. Plant output in terms of kWh generation varies with the system energy requirements; therefore, all variable costs of production are assigned to customers based on their energy usage.

Witness Hager commented that in supporting the SWPA methodology, witness McLawhorn fails to acknowledge that the COSS in this proceeding already classifies over $2 billion of production costs (fuel, purchased power, O&M, etc.) as variable, and allocates these costs to the jurisdiction and customer classes using an energy allocator. Witness Hager stated that the SWPA method would allocate a higher portion of the fixed costs to the higher load factor customers. According to Hager, advocates for this method feel this is equitable on the theory that high load factor customers benefit from the lower energy costs that result from the operation of base load plants as opposed to the higher energy costs of peaking plants. However, witness Hager stated that proponents never carry this argument to its logical conclusion. That is, those customers allocated the higher capital costs based on energy usage should be allocated the lower variable operating costs of those same base load facilities. Witness Hager noted that if the primary theory behind the use of the SWPA allocation methodology is that fixed production plant costs are incurred to meet both capacity and energy requirements, then it seems only fair and equitable that high load factor customers should be allocated more of the lower variable energy costs, while low load factor customers should be allocated more of the higher variable energy costs.

Witness Hager also testified that she does not agree with witness Phillips' recommended use of the winter peak for the allocation of demand-related production and transmission costs. Witness Hager stated that the generation and transmission asset costs to be recovered in this proceeding were constructed based upon customers' contribution to the summer coincident peak. Therefore, SCP is the appropriate allocation methodology in this case and to focus on the converging summer and winter peaks in the rate design as has been done by Company witness Pirro. Witness Hager also expressed concerns with the volatility of the winter peak and the volatility that using a single winter peak could introduce into customer rates.

Witness Hager next turned her attention to the MSM. She stated that the NARUC cost allocation manual specifically states in the section on allocation of embedded costs that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system." She stated that witness Wallach contends that customer connection costs are generally limited to plant and maintenance costs for a service drop and meter, along with meter reading, billing, and other customer-service expenses. Witness Hager noted that witness Wallach quotes Bonbright's Principles of Public Utility Rates to support his argument noting that the text says that metering and billing expenses are the most obvious examples of customer costs. She commented that witness Wallach fails to mention that the quoted text does not say these are the only costs. Further witness Hager stated that while it is true that Dr. Bonbright recognizes the difficulty of determining the proper allocation for the minimum system costs, he concludes that the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs. According to witness Hager Bonbright recognizes that utilities must distribute all costs among the classes of customers in a fully distributed cost analysis. Witness Hager stated that even more important is the NARUC cost allocation manual that was developed after Dr. Bonbright's work. She commented that the cost allocation manual moved from the theoretical world of Dr. Bonbright to the reality of utilities' needs to move from development of revenue requirements to rate structures.

Witness Hager also testified that DEP does not support witness O'Donnell's proposed allocation of coal ash compliance costs. She explained that DEP used an energy allocation factor in compliance with the 2018 DEP Rate Order. Witness Hager further stated that the method proposed by witness O'Donnell is not consistent with that

Order nor does it follow cost causation principles. She noted that costs are not "caused" by the relative impact of rates on classes of customers.

Stipulations

As part of the CIGFUR Stipulation the parties agreed to meet prior to the Company's next general rate case to discuss potential costs of service methodologies that the Company may recommend for the purpose of allocating production and transmission costs. In addition, in its next general rate case the Company shall also file the results of a class cost-of-service study with production and transmission costs allocated on the basis of the SWCP method and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes. Further, the parties agreed that in its next general rate case the Company will adjust its peak demand to remove curtailable/non-firm load even if it does not call the load. If the Commission approves this adjustment in the Company's next general rate case, then DEP will propose use of this adjustment in its next subsequent rate case. Finally, the parties agreed that in its next three general rate cases DEP would propose to allocate distribution expenses using the MSM; however, if the Commission orders a different approach be used in the current rate case or either of the next two rate cases, DEP may elect to propose the MSM in the next subsequent rate case after the NCUC denial, but DEP is not obligated to do so.

The Public Staff Second Partial Stipulation states that for this case only the Public Staff accepts, subject to the conditions in Section IV.B, the Company's proposal to calculate and allocate the Company's cost of service based on a SCP methodology. However, the Second Partial Stipulation also states that this provision shall not constitute precedent and shall have no effect on the Rate Design Study proposed by the Public Staff and agreed to by the Company. Further, Section IV.B states that DEP has based its filing in this docket on the SCP methodology for cost allocation among jurisdictions and among customer classes. However, the parties agreed that prior to the filing of its next general rate case the Company shall undertake an analysis of additional cost of service studies subject to the following conditions:

(1) The Company agrees to analyze and develop cost of service studies based on each of the following methodologies:

a. Single Summer Coincident Peak;

b. Single Winter Coincident Peak;

c. One that utilizes the four highest monthly system peaks (two monthly peaks in summer and two monthly peaks in winter);

d. SWPA;

e. Base Intermediate and Peak (as described in the Regulatory Assistance Project (RAP) “Electric Cost Allocation for a New Era” Manual, published January 2020); since the Company’s accounting systems do not have the data developed to produce such a study, this methods may be analyzed by looking at how it has been used at another utility or with a higher level hypothetical analysis;

f. One that utilizes the twelve highest monthly system peaks in the test year; and

g. Any other identified relevant methodologies.

(2) Each methodology studied will include an evaluation of the allocation of the functions of utility service (production plant, transmission plant, distribution plant, and customer costs), including an identification of which cost components associated with these functions of utility service are fixed, and which are variable costs of service. The above methodologies only impact production and transmission allocations; however, the cost of service studies will show the allocation of all functions. For purposes of these studies, all demand and customer classified costs can be designated as fixed and all energy classified costs can be designated as variable.

(3) Each methodology studied will include an evaluation of its strengths and weaknesses on both a jurisdictional and class allocation basis.

(4) Included in the studies shall be a discussion of how the allocation of fuel and other variable operations and maintenance (O&M) expenses align with system planning.

(5) The Company shall consult with the Public Staff and any other interested parties throughout the study process.

Further, the parties agreed that the Company will continue to file annual cost-of-service studies based on both the SCP and SWPA methodologies until instructed to do otherwise by the Commission. The Company also agreed that it will not cite Commission approval of the Second Partial Stipulation as support for approval of the SCP methodology in future proceedings.

Discussion and Conclusions

The Commission gives significant weight to the testimony of DEP witness Hager and determines that having the necessary generation and transmission resources to meet the Company’s summer peak, plus an appropriate reserve margin, is an essential planning criterion for the Company’s system. Under cost causation principles all customer classes should share equitably in the fixed production and transmission costs of the system in relation to the demands they place on the system at the peak.

Although the Public Staff has traditionally supported the SWPA methodology, it is not unreasonable for the Public Staff to have agreed to the use of SCP in this proceeding. The Commission gives significant weight to the Public Staff's Second Partial Stipulation.

Further, the Commission gives significant weight to witness Hager's testimony concerning the Company's long history of employing the minimum system method and the method's alignment with cost causation principles. According to witness Hager's testimony, after the Company determines the customer-related costs using the MSM, the remainder of distribution costs are classified as demand-related and are allocated based on NCP demand. Witness Wallach recommended that the Commission reject the Company's use of the NCP demand to allocate distribution costs. The Commission gives little weight to witness Wallach's recommendation on this position. The Commission gives more weight to witness Hager's testimony that NCP is the appropriate measure for determining customers' responsibility for these costs.

Finally, the Commission concludes that the provisions of the CIGFUR Stipulation that commit DEP to take specific positions on certain issues in DEP's next several rate cases, such as adjustments to peak demand and use of the minimum system approach, are not relevant to any issue before the Commission in this docket. Under the guidelines set forth in *CUCA I* and *II*, a nonunanimous stipulation is evidence; however, the Commission can only use relevant evidence as the basis for its decisions. The CIGFUR Stipulation and DEP agreements on future proposals and positions in future rate cases have no relevance in this rate case, and the Commission therefore declines to accept those portions of the CIGFUR Stipulation.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that the greater weight of the evidence shows that the SCP cost of service methodology provides the most appropriate methodology to assign fixed production and transmission costs in this proceeding.

The Commission finds and concludes that the Public Staff's Second Partial Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the Second Partial Stipulation is material evidence to be given appropriate weight in this proceeding.

Moreover, as demonstrated by the opposing testimony between DEP and CIGFUR witnesses, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the parties during their settlement negotiations in an effort to appropriately balance DEP's usage of the SCP and CIGFUR's desire to investigate a different methodology for the sole purpose of apportionment of the change in revenue to the customer classes in the next general rate case. The Commission finds and concludes that the CIGFUR Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the provisions of the CIGFUR Stipulation not otherwise rejected by the Commission are relevant and material evidence to be given appropriate weight in this proceeding.

Further, the Commission finds and concludes that the Company's use of the MSM for cost allocation in this proceeding is just and reasonable to all parties in light of all of the evidence presented. The Commission also finds and concludes that NCP is the appropriate measure for determining customers' responsibility for demand-related distribution costs after the customer-related costs are determined using MSM.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

Rate Design

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations between DEP and various parties; the testimony and exhibits of DEP witnesses Pirro, Huber, and Hager, Public Staff witness Floyd, NCJC et al. witnesses Wallach and Howat, NCSEA witness Barnes, Harris Teeter witness Bieber, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness Pirro provided an overview of the Company's proposed rate design. Tr. vol. 11, 1086-88. Witness Pirro noted that when moving rate schedules and riders closer to a more cost-justified basis it is important to consider the impact upon customers and employ the principle of gradualism. *Id*. at 1089. He testified that this principle was applied in this case to update price relationships and levelize the percentage change in revenues on participants within the rate class while still moving towards a more equitable pricing structure. *Id.* at 1089-90.

Witness Pirro testified that the Company is not proposing any new peak time pricing rate designs offering real time price signals in this proceeding. He stated, however, that the Company is actively monitoring DEC's recently implemented dynamic pricing pilots to evaluate the effectiveness of dynamic pricing on residential and small nonresidential customers. According to witness Pirro, the pilots include review and analysis of rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service.

Witness Pirro testified that the Company's unit cost study indicates it is appropriate to raise the monthly BCC to better reflect all customer-related costs. Tr. vol. 11, 1089, 1121-22. He indicated that to do otherwise would result in customer cross-subsidization. Witness Pirro stated that the Company would normally propose the BCC for all rate classes be set to recover approximately 50% of the difference between the current rate and the full customer-related unit cost incurred to serve the customer groups. However, according to witness Pirro the Company decided in this rate case proceeding not to increase the BCC but, rather, to leave it at current rates due to past concerns raised by low-income and other advocates with respect to the level of the charge. *Id.* at 1089, 1122.

Witness Pirro also detailed, and testified in support of, the Company's proposed changes to its outdoor lighting schedules (SLS, SLR, ALS). *Id.* at 1103-07. In addition to changes to specific lighting rates, the Company also requested approval to: (1) eliminate high pressure sodium (HPS) lighting options for new installations under each lighting schedule, and offer LED lighting for those installations; (2) require replacement of existing mercury vapor (MV) lighting and related fixtures by the end of 2023; (3) modify the term for lighting contracts from one to three years; and (4) make Schedule SLR subject to the Company's Outdoor Lighting Service Regulations. *Id*. at 1104-06.

Public Staff Testimony

Witness Floyd testified that the Company made very few modifications to any of its rate schedules other than to increase individual rate elements within each schedule to accomplish the revenue increase assigned to the rate class itself, including retaining the same relationships between the summer and winter rates. Tr. vol. 15, 957. He noted that the current rates had not yet been updated to incorporate new AMI data analytics and the Company should begin incorporating AMI data into its load research efforts supporting rate design. *Id*. at 957, 966-67. However, witness Floyd stated that notwithstanding his testimony highlighting the status quo nature of the Company's rate schedules, he is generally supportive of the few proposed changes to rate schedules and service regulations discussed by witness Pirro. *Id.* at 958, 1008.

With respect to the Company's lighting rate schedules, witness Floyd indicated that he reviewed the cost data provided by the Company regarding the proposed changes to individual rates under each lighting schedule and believes the changes in rates and the related lighting services are reasonable and should be approved. *Id.* at 963. With respect to the contract terms and the application of the lighting service regulations to Schedule SLR, he concluded that both changes are reasonable attempts to consolidate the terms and conditions applicable to lighting services and each lighting rate schedule. *Id*.

Witness Floyd also stated that it is appropriate for DEP to begin working on new EV rates and to discuss design options with stakeholders. Tr. vol 15, 958. He proposed that the Commission require DEP to develop and propose EV rate designs as part of his recommended larger rate design study.

Witness Floyd further stated that the Public Staff does not object to the Company's proposal to leave BCCs at current levels for purposes of this proceeding. *See id.* at 1045-47, 1095-96.

Witness Floyd also testified that the Public Staff believes the Company should undertake a comprehensive rate design study prior to the filing of its next rate case to allow stakeholders the opportunity to participate in the discussion and he articulated six broad principles he believed were appropriate for future rate designs. *Id.* at 968-69. Witness Floyd provided several examples of utility services that justify the need for a comprehensive study, including net metering and other distributed generation resources, microgrids, energy storage, and electric vehicles (EVs). *Id.* at 969-70.

Finally, witness Floyd testified that the Public Staff supports convening a stakeholder process to address affordability issues, including the appropriate amount of the BCC.

NCJC et al. Testimony

Witness Wallach recommended that the Company's request to maintain the residential BCC at its current rate of $14.00 per bill be denied. He instead recommended that the residential BCC be reduced to $9.63 per bill, reflecting the actual cost to connect a residential customer. Tr. vol. 14, 409, 435, 437. Witness Wallach testified that consistent with long-standing cost-causation and rate-design principles, a monthly BCC of $9.63 would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer. He contested the Public Staff's Minimum System Report and the conclusion that it is generally reasonable to use the results of a minimum system approach for setting the maximum allowable amount that could be recovered in a basic customer charge. *Id.* at 410, 446-455.

Witness Howat also recommended that the Commission reject the $14.00 residential BCC because it inappropriately reflects usage-related costs and would result in subsidies of high-usage consumers by low-usage customers, discourages energy efficiency, and disproportionately harms certain households.

NCSEA Testimony

Witness Barnes provided extensive testimony on his proposal that the Commission direct DEP to establish EV specific rates for both home charging and commercial charging applications. Tr. vol. 14, 463-66. Witness Barnes recommended that the Commission direct DEP to file separate, targeted EV-specific tariffs for both residential and nonresidential dedicated EV charging, reflecting the core characteristics discussed in his testimony. He stated that this should occur within 60 days of the order in this rate case.

Further, witness Barnes recommended that the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates, lessons learned, and potential refinements.

Harris Teeter Testimony

Witness Bieber testified that DEP's proposed rate design for the SGS-TOU rate schedule significantly understates demand related charges while overstating the energy charges relative to the underlying cost components, based on the Company's own COSS.

According to witness Bieber the proposed rate design in this case would worsen the existing misalignment between SGS-TOU charges and cost causation relative to current rates. He recommended modifications to the proposed SGS-TOU rate design that he stated would improve the alignment between the rate components and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. Further, witness Bieber recommended that the Company study the feasibility of a multi-site aggregate commercial rate and propose a pilot program in its next rate case. Tr. vol. 15, 229-30, 252-55.

CUCA Testimony

Witness O'Donnell testified that DEP's industrial customers take advantage of the hourly pricing rate offered by the Company. However, witness O'Donnell testified that recently there have been concerns from manufacturers regarding the excessive costs of Duke's hourly prices in relation to prices found in other parts of the country. Further, witness O'Donnell testified that since Duke operates a closed system and prices its RTP costs at its own marginal costs, manufacturers are paying higher costs than necessary. He stated that he sees no reason why DEP should not be ordered to set the RTP rates at the lower of the Company's marginal cost or the price as set by the open wholesale power market, as adjusted for transmission costs and line losses for moving the power to the DEP service territory.

Hornwood Testimony

Witness Coughlan testified that DEP's LGS-RTP schedule currently has a cap of 85 customers and is fully subscribed. Witness Coughlan advocated for lifting the cap to allow customers such as Hornwood to participate. Tr. vol. 14, 550-51, 581. He stated that the 85 customers currently served under the RTP rate enjoy an unfair competitive advantage over the thousands of customers who are not allowed to receive service under this rate. Further, witness Coughlan testified that customers served under this rate have the ability to shift their load in response to strong pricing signals.

DEP Rebuttal Testimony

DEP witness Huber testified that he agreed that the Company should conduct a comprehensive rate design study. Tr. vol. 11, 1156-57. Further, witness Huber proposed that DEP complete the study by the end of the second quarter of 2021.

Witness Huber testified that the Company cannot cost-effectively implement any rate design changes until the new Customer Connect billing system is in use. He stated that because it is more cost-effective to implement new rates concurrently with the new billing system, DEP strongly favors utilizing the time prior to implementation to analyze data, convene stakeholders, and refine its proposals. According to witness Huber Customer Connect is scheduled to be implemented for DEP in the spring of 2022. Once the new Customer Connect system is fully deployed and post-deployment stabilization is achieved approximately six months later, the Company will be ready to begin implementing new rate designs.

Witness Huber stated that DEP is also open to looking into rate designs that support the adoption of electric vehicles. Tr. vol. 11, 1159. He testified, however, that the Company believes that it is inappropriate for the Commission to expedite the filing of electric vehicle-specific tariffs within 60 days of the final order in this case as recommended by witness Barnes. Rather, witness Huber suggested a study of rate designs that facilitate the adoption of EVs that provide system benefits for all customers should be a part of the comprehensive rate design study. *Id*.; *see also id.* at 1211-14.

Finally, witness Huber addressed witness Bieber's recommendation that the Commission order the Company to study the feasibility of a multi-site aggregate commercial rate and propose a pilot program in its next rate case. Witness Huber testified that DEP believes that it is premature for the Commission to order the Company to conduct such a study but stated that the Company is willing to consider the proposal in the context of the comprehensive rate design study.

Witness Pirro stated his disagreement with, and gave a number of reasons not to adopt, witness Coughlan's recommendations to increase the number of participants on LGS-RTP. *See* Tr. vol. 11, 1138, 1141, 1318-23, 1325-29. Among other things, witness Pirro explained that the hourly rates under LGS-RTP are calculated based upon the marginal or dispatch cost of the generator that is expected to serve the next kWh of system load based upon all available generating plants, and that these hourly rates are based on variable production cost data from an industry standard production cost model, which is updated daily to reflect the latest available information such as weather and load forecast, unit availability, heat rates, and variable commodity and emission costs. *Id*. at 1138-39. He also clarified that participants do not receive preferential pricing but rather the opportunity to modify their operations to respond to price signals, which carries a risk – "[i]f they don't respond, they will be paying more during those hours." *Id*. at 1321. Witness Pirro testified that a change in the rate design of the LGS-RTP tariff would require significant analysis and stakeholder engagement and suggested that this discussion should be a part of the comprehensive rate design study.

Further, witness Pirro testified that he disagrees with the recommendation of witness O'Donnell that the hourly rate be set at the lower of the Company's marginal cost or a wholesale market rate. *Id.* at 1140. He testified that the Schedule LGS-RTP hourly rates are fundamentally based on the Company's system production costs and are not designed to represent market-based pricing. According to witness Pirro the RTP product is not a market product and was never intended to provide some customers with optionality beyond the ability of the Company to provide appropriately priced service. Witness Pirro testified that the current methodology best reflects the Company's expected fuel cost and is therefore the appropriate basis under which to set hourly rates. *Id.*

Witness Pirro also disagreed with NCJC et al.'s position that the current residential BCC should be reduced. Tr. vol. 11, 1121-22. He explained that the rates and rate design supported by his testimony are based upon the COSS, including the minimum system study, performed by the Company, accepted by Public Staff, and approved in previous rate cases by the Commission. *Id.* The Company's cost-of-service studies indicate that these costs are customer costs, with the BCC designed to recover them. Witness Pirro also testified that failing to properly recover customer-related costs via a fixed monthly charge would provide an inappropriate price signal to customers and would fail to adequately reflect cost causation. *Id.* at 1123.

Similarly, witness Hager explained why it is appropriate to include uncollectible costs in the customer classification for inclusion in the BCC. *Id.* at 1067. In particular, she testified that witness Wallach's claim that uncollectible costs "tend to vary with revenues and thus with usage" is unsupported. *Id.*

Stipulations

Public Staff Second Partial Stipulation

In Section IV.C the Company agreed, consistent with the rate design principles articulated by witness Floyd, that any proposed revenue change will be apportioned to the customer classes such that: (1) any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock; (2) class RORs are maintained within a band of reasonableness of plus or minus 10% relative to the overall North Carolina retail ROR, and for class RORs currently above the band of reasonableness, the Company will gradually move class RORs closer to the band of reasonableness; (3) all class RORs move closer to parity with the North Carolina ROR; and (4) subsidization among the customer classes is minimized.

In Section IV.D DEP and the Public Staff agreed, as indicated by witness Floyd, that the proposed modifications to the Company's rate schedules are reasonable for purposes of this proceeding. The parties also agreed that the Commission should order a comprehensive rate design study that will address rate design questions.

In Section IV.G DEP agreed that it will develop and propose EV rate designs as part of the comprehensive rate design study.

CIGFUR Stipulation

In the CIGFUR Stipulation DEP agreed that should it independently undertake or should the Commission order a comprehensive rate design process prior to the Company's next general rate case, DEP agrees to explore the following: (1) a rate schedule targeted at high load users similar to Duke Energy Indiana's HLF rate; (2) allowing RTP customers to adjust Customer Baseline Loads (CBL) to enhance RTP usage, including additional special periods of adjustment; (3) an emergency demand response program similar to Southern California Edison's Time-of-Use-Base Interruptible Program (TOU-BIP) tariff; and (4) a rate schedule similar to the Northern Indiana PSC

Interruptible Industrial Service Rider. If there is mutual agreement between parties on the terms of any of the above-reference rates, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, DEP agrees to file said rates for approval in its next rate case filing. If DEP does not undertake a comprehensive rate design process DEP agrees to consult with CIGFUR on points 1 through 4 as mentioned above. In the event that rates proposed by DEP pursuant to points 1 through 4 as mentioned above are withdrawn by DEP or are not approved by the NCUC, DEP shall be obligated to work with CIGFUR to identify an agreeable alternative. If at least one of CIGFUR's member customers is willing to take service on the agreeable alternative rate(s), DEP agrees to file said alternative rates with the NCUC in its subsequent rate case filing.

Further, CIGFUR and DEP agreed that the LGS, LGS-TOU, and LGS-RTP on-peak and off-peak energy charges shall be increased by a percentage that is less than half of the approved overall increase percentage exclusive of any EDIT decrements for the LGS, LGS-TOU and LGSRTP and rate schedules, respectively. The demand charges for the LGS, LGS-TOU and LGS-RTP rate schedules shall be adjusted by the amount necessary to recover the final LGS, LGSTOU and LGS-RTP revenue targets, respectively.

Finally, DEP agreed to propose the uniform percentage average bill adjustment methodology most recently approved by the NCUC in DEP's 2019 fuel cost recovery proceeding in the next two annual fuel cost recovery proceedings (2021 and 2022).

The Commercial Group and Harris Teeter Stipulations

In the Commercial Group Stipulation the parties agreed that the percentage base rate increase for Rate Schedule SGS-TOU and Rate Schedule MGS shall be the same, with the exception that DEP shall have the right to adjust the rates for Rate Schedule CSE and Rate Schedule CSG more than the percentage base rate increase for Rate Schedule MGS as may be necessary to address concerns raised by the Public Staff. Further, the parties agreed that the SGS-TOU on-peak and off-peak energy charge shall be increased by a percentage that is no greater than half of the approved overall increase percentage. The demand charges for the SGS-TOU rate schedule shall be adjusted by the amount necessary to recover the final SGS-TOU target revenue.

In the Harris Teeter Stipulation the parties agreed that any GIP costs allocated to SGS-TOU customers shall be recovered via SGS-TOU demand charges. The parties agreed that the SGS-TOU on-peak and off-peak energy charges shall be increased by a percentage that is no greater than half of the approved overall increase percentage for the SGS-TOU rate schedule. The demand charges for the SGS-TOU rate schedule shall be adjusted by the amount necessary to recover the final SGS-TOU revenue target. Further, the parties agreed that the percentage base rate increase for Rate Schedule SGS-TOU and Rate Schedule MGS shall be the same. However, DEP shall have the right to adjust the rates for Rate Schedule CSE and Rate Schedule CSG more than the percentage base rate increase for Rate Schedule MGS as may be necessary to address the Public Staff's concerns.

Discussion and Conclusions

The Commission concludes that the Company's proposed portfolio of rate designs as modified by this Order, specifically including the rate design provisions outlined in §§ IV.C and D of the Public Staff Second Partial Stipulation, are just and reasonable for purposes of this proceeding. Nonetheless, as the Company and customers adopt new technologies and uses of the electric system change, rate design must evolve in order to maximize the efficiency and effectiveness of these new technologies and ensure usage of the electric system that is consistent with the public interest. The Commission recognizes the impact the results of a comprehensive rate study may have on future utility services, customers, and the economy of the State. That said, the Commission concludes that it is in the public interest to direct the Company to conduct a comprehensive rate design study (Rate Design Study) as outlined in § IV.E of the Second Partial Stipulation and further described in the testimony of witnesses Floyd and Huber, and as expanded upon herein. Based on the evidence in the record, the Commission provides the following guidance.

With respect to scope, the Rate Design Study should address, at a minimum, those rate design questions set forth in § IV.E(1)–(6) of the Second Partial Stipulation, including firm and non-firm utility services, various types of end uses (EVs, microgrids, energy storage, and DERs), the formats of future rate schedules, marginal cost versus average cost rate designs and pricing, unbundling of average rates into the various functions of utility services, and socialization of costs versus categorization of specific costs. The Rate Design Study should include but not be limited to these topics. The Commission is persuaded that in depth evaluation, debate, and discussion by and among stakeholders regarding cost to serve, rate design, and making the most efficient use of the electric system is necessary to achieve results that are in the public interest, and the Commission directs the Company to ensure that all necessary and appropriate topics are considered, to this end. For example, the Commission notes that § V.E of the CIGFUR Stipulation includes commitments by the Company in the event that the Commission directs the Company to undertake a comprehensive rate design study. Notwithstanding the foregoing, the Commission directs the Company and all parties that participate in the Rate Design Study to work cooperatively, productively, and efficiently to ensure that resources are efficiently expended on this endeavor and that the outcome aligns with the public interest.

In response to Commission questions, witness Huber confirmed that the issue of the rates and charges for services for net metering customers would be a part of the Rate Design Study. Tr. vol. 11, 1164. Thus, the Commission anticipates and expects that net metering will be considered in the Rate Design Study and that consistent with N.C.G.S. § 62-126.4(b), the Rate Design Study will address the costs and benefits of customer-sited generation.

With respect to the recommendations of NCSEA witness Barnes regarding EV charging rates, the Commission determines that the development of such rates is most appropriately evaluated in the context of the Rate Design Study as opposed to in a separate proceeding. Thus, the Commission directs the Company to include the investigation of EV rate designs in the Rate Design Study.

Similarly, with respect to the recommendations of CUCA regarding the development of interruptible rates for large industrial customers, the Commission concludes that the development of such rates is most appropriately evaluated in the context of the Rate Design Study.

Witness Floyd testified that rate design should follow the same cost causation approach underlying the COSS, such that each customer class, or customer, is responsible for an appropriate share of the costs that are planned for and incurred in order to serve them. This includes both fixed and variable costs. Witness Floyd testified that the Company's rate schedule portfolio does not align with its COSS in this proceeding. He stated that the Company continues to rely on its historical use of the SCP COSS methodology which is inconsistent with the winter peaking characteristics of the Company's overall system. However, according to witness Floyd DEP's existing rate schedule portfolio remains oriented around summer peaking utility service. Tr. vol. 15, 955-956.

Witness Floyd also testified that a comprehensive study should encompass the issues facing the utility of the future, particularly those issues discussed in testimony. Witness Floyd noted that the Company is already conducting a study of its cost-of-service. A study of rate designs should follow soon thereafter. According to witness Floyd, both are inextricably related. Rate designs should be rooted in a few broad principles that require rates to:

(1) Be forward-looking and reflect long-run marginal costs.

(2) Be focused on the usage components of service that are the most cost- and price-sensitive.

(3) Be simple and understandable.

(4) Recover system costs in proportion to how much electricity consumers use, and when they use it.

(5) Give consumers appropriate information and the opportunity to respond to that information by adjusting their usage.

(6) Where possible, be dynamic.

These guiding principles must allow consumers and users of the electric system to connect to the utility system for no more than the cost of connecting to the grid; pay for utility service in proportion to how much they use the system; and receive fair and just compensation for the energy they supply to the utility system. *Id*. at 968-69. Thus, the Commission directs the Company to undertake the Rate Design Study through the process envisioned by witness Floyd.

Further, as recommended by witness Floyd, the Commission finds that the Rate Design Study should: (1) include an analysis of each rate schedule to determine whether the schedule remains pertinent to current utility service, including whether the schedule should remain the same, be modified, or be replaced; (2) address the potential for new schedules to address the changes affecting utility service; (3) provide more rate design choices for customers; and (4) explore the feasibility of consolidating the rates offered by DEC and DEP. *Id*. at 968.

CIGFUR in its post-hearing brief stated that the rate design provisions contained within the CIGFUR Stipulation serve the public interest in that they will allow for collaborative, constructive conversations between CIGFUR and the Company in furtherance of the goal to design rates that: (1) more accurately reflect fuel costs by time of day and season and charge customers for the actual cost of fuel in a more precise manner than an annual average uniform charge on all energy; (2) promote demand-response mechanisms that offer lower rates for metered decreases in demand when reductions in demand are in the economic and operating interests of the Company and, thus, the financial interests of ratepayers; (3) allow for trade-offs between reliability and economic considerations that industrial, high-load factor ratepayers can weigh through interruptible rates, benefitting both the Company and all classes of ratepayers; (4) include real-time pricing with attendant options and risk variations; and (5) reflect that some industrial, high-load factor ratepayers have independent backup and/or cogeneration resources. The Commission finds that these goals articulated by CIGFUR will serve the public interest and should inform the work of the rate design effort.

Company witness Huber indicated that the Company is open to a third-party facilitator for the stakeholder portion of the Rate Design Study. Tr. vol. 11, 1212. The Commission agrees that the use of an independent facilitator would be appropriate and, thus, directs the Company to engage a third party for this purpose.

The Commission declines to adopt Hornwood witness Coughlan’s recommended changes to expand the availability the LGS-RTP rate schedule in this case. Witnesses Pirro and Floyd both offered convincing testimony that while this issue warrants additional study, it would be inappropriate to open the LGS-RTP rate to additional customers at this time. In particular, the Commission gives weight to their testimony relating to the burden of administering the rate, the fact that the original rate was designed for large customers, and importance of examining the greater economic implications. Tr. vol. 11, 1318-32; tr. vol. 15, 1131-32. The Commission agrees it would be more appropriate to reevaluate this rate schedule in the broader context of examining RTP and TOU opportunities during the comprehensive rate design study, and in view of the implementation of Customer Connect.

The Commission also concludes that it is premature to order the Company to propose a multi-site aggregation pilot in its next rate case, as proposed by Harris Teeter witness Bieber. Tr. vol. 15, 229-30, 252-55. The Commission agrees with DEP, however, that it is appropriate that a multi-site aggregate commercial offering be considered in the comprehensive rate design study, including the purpose of the aggregation, the impact on cost of service, the potential for revenue realignments, and the implications for other aspects of utility service outside of base revenues.

The Commission recognizes that both witness Floyd and witness Huber provided testimony about how cost of service informs and translates into rate design. The Company has agreed to consider and prepare cost of service studies using a number of methodologies in its settlements with CIGFUR and the Public Staff, however, the Commission finds that these cost of service studies are separate and apart from the comprehensive rate design study. While a rate design study would necessarily include analysis and discussion of how rate designs align with different cost of service metrics, the Commission determines that stakeholder discussion of the appropriate allocation methods (e.g., cost of service allocators) need not be included in the rate design study. Instead, the focus of the comprehensive rate design study should remain on the guidance outlined above.

All parties to the rate case proceeding should be afforded the opportunity to participate as stakeholders in the Rate Design Study. The Commission directs the Company to initiate the Rate Design Study with stakeholders no later than 30 days following the issuance of this Order.

With respect to timing, as indicated by witness Huber’s testimony that the Rate Design Study will yield a detailed “roadmap” within a year, Tr. vol. 11, 1273, the Commission directs the Company to file a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study within 12 months of this Order. In addition, the Commission directs the Company to file quarterly status reports in the instant docket, providing, in detail, the work of the Rate Design Study participants over the previous quarter, including objectives achieved, and anticipated work to be undertaken going forward, including objectives to be achieved.

Finally, the Commission recognizes that the Rate Design Study and the affordability collaborative described hereinafter are separate but parallel efforts. To the extend the parties participating in the affordability collaborative recommend the design of new rates to offer to low-income customers, the parties should present those recommendations to the rate design study participants for consideration. Additionally, the Commission does not intend for the stakeholder processes for affordability and the Rate Design study to be mutually exclusive or contingent upon the completion of either stakeholder process.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-54

Affordability

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations between DEP and various parties; the testimony and exhibits of DEP witnesses De May and Pirro, Public Staff witness Floyd, and NCJC et al. witness Howat; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

Witness De May testified that DEP is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship. He outlined several existing programs that have helped many of their customers in this regard. Witness De May stated that DEP is convinced that additional low-income energy assistance programs can be offered to aid customers in need of support. Further, he stated that stakeholder engagement is necessary to adequately develop an appropriate suite of effective options for the Commission to consider for approval. The Company requests that the Commission direct the Company to host, and the Public Staff to participate in, a collaborative workshop with interested stakeholders to address the establishment of new low-income programs.

Public Staff Testimony

The Commission's January 22, 2020 Order directed the Public Staff to "investigate DEP's analysis of affordability of electricity within its service territory as well as programs available to DEP's customers that address affordability with a particular focus on residential energy customers." In the Order the Commission directed the Public Staff to address the following issues:

(1) An overview of Lifeline Rates and whether this approach would be appropriate for North Carolina;

(2) The applicability, design, and effectiveness of DEC's Supplemental Security Income (SSI) discount;

(3) A comparison of the SSI discount to other tariffs available to customers that address affordability issues;

(4) An overview of similar affordability tariffs or plans available by the other affiliates of DEP; and

(5) The merits of using a "minimum bill" concept in lieu of a fixed customer charge.

Public Staff witness Floyd addressed each of these issues in his testimony. Consistent with the Company's request as discussed by witness De May, witness Floyd stated that the Commission should order the convening of a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

NCJC et al. Testimony

Witness Howat provided extensive testimony on issues related to affordability of electric service for DEP's lower-income residential customers, and discussed programs and policies designed to mitigate affordability challenges faced by those customers. Witness Howat outlined policy objectives and program design elements featured in effective programs, provided brief descriptions of a sampling of investor-owned utility bill affordability programs operating in the United States, and recommended that the Commission initiate a process culminating in approval of funding and implementation of enhanced low-income bill payment assistance programming and low-income residential energy-efficiency programming in the DEP service territory. Finally, witness Howat recommended that the Commission direct DEP to expand the Helping Home Fund and consider shifting it from a shareholder- to a ratepayer-funded program.

DEP Rebuttal Testimony

Witness Pirro noted that witness Howat sought changes to the Company's energy efficiency programs targeting low-income customers. Witness Pirro stated that the issue of whether DEP should propose additional energy efficiency programs or modify existing programs should be addressed in DEP's DSM/EE proceedings.

DEP witness Pirro stated that the Company is mindful of the impact of any rate increase on customers, particularly low-income customers; however, the Company does not design rates based on income but rather applies cost causation principles to the extent practical. Witness Pirro also stated that there are other means of addressing the financial needs of low-income customers, such as Company, state, and local programs, which are more effective than biasing the rate design. Nevertheless, witness De May stated that the Company supports a dialogue on ways to mitigate electricity costs for low-income customers. He stated that the Company looks forward to the opportunity to engage with its interested stakeholders in a collaborative workshop to address this important issue.

Stipulations

In the NCSEA/NCJC et al. Stipulation DEP agreed to provide, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million).

Further, the parties also agreed that within six months of the effective date of the stipulation, in addition to the low-income collaborative proposed by DEP, to collaborate to design additional low-income DSM/EE program pilots to present to the DEC and DEP DSM/EE Collaborative for consideration.

In the Public Staff Second Partial Stipulation the parties agreed that the Commission should order the Company to convene a stakeholder process that is tasked with addressing affordability issues for low-income residential customers, with a timeline for the process, including deadlines for periodic reporting and filing recommendations to the Commission. The parties proposed one year for this process. The Company also agreed to make an annual $2.5 million shareholder contribution to the Energy Neighbor Fund in 2021, and 2022, for a total contribution of $5 million. Second Partial Stipulation § IV.P.

DEP witness De May discussed in his second settlement testimony how the partial settlement balances the Company's need for rate relief with the impact of such rate increases on customers. Witness De May stated that he attended public hearings held by the Commission in this matter and personally heard from many customers who are concerned about the impacts of any rate increase on their families and businesses. Witness De May stated that DEP is very mindful of these concerns. Further, he stated, in light of the current economic conditions of many customers due to the COVID-19 pandemic, the Company believes that the concessions the Company has made in the Partial Settlement fairly balance the needs of customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to customers. Witness De May stated that the Company agreed to make an annual $2.5 million shareholder contribution to the Energy Neighbor Fund in 2021 and 2022, for a total contribution of $5 million.

Discussion and Conclusions

The Commission gives significant weight to the testimony of Public Staff witness Floyd addressing the affordability issues raised in the Commission's January 22, 2020 order.

In addition, the Commission gives weight to the extensive testimony of NCJC et al. witness Howat concerning affordability. Witness Howat's comments on the need for low-income affordability programs, policy objectives and program design elements featured in effective programs, as well as descriptions of investor-owned utility bill affordability programs are most informative.

The Commission also gives weight to the information provided in the late-filed exhibits of NCJC et al., which are sufficiently responsive to Commission questions posed during the hearing.

The Commission gives significant weight to the provisions of the NCSEA/NCJC et al. Stipulation and the Public Staff's Second Partial Stipulation, each of which recommend a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that it is appropriate for the Company to convene a stakeholder process (collaborative) that is tasked with addressing affordability issues for low-income residential customers, with a timeline for the process, including deadlines for periodic reporting and filing recommendations to the Commission. Both Company and intervenor witnesses highlighted the need for direction from the Commission in establishing the goals and parameters of the stakeholder process.

The Commission directs that the collaborative shall abide by the same provisions and time frames set out in the recently issued DEC Rate Case Order in Docket No. E-7, Sub 1214, and hereby incorporates by reference the guidance set forth in that Order. *See* Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1214, at 176-79 (N.C.U.C. March 31, 2021).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 55-61

Storm Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff First Partial Stipulation; the testimony and exhibits of DEP witnesses De May, Jackson, and Smith, and Public Staff witness Dorgan; and the entire record in this proceeding.

Summary of the Evidence

DEP Direct Testimony

In its Storm Cost Petition, filed in Docket No. E-2, Sub 1193, the Company sought authorization from the Commission to defer certain storm response costs incurred by the Company in responding to Hurricanes Florence and Michael and Winter Storm Diego.

In its Application the Company proposed to consolidate its Storm Cost Petition with the rate case and to recover its Storm Costs through a revision to its base rates. It also proposed to consolidate its request for storm cost recovery related to 2019 storm Hurricane Dorian with its request for cost recovery related to Hurricanes Florence, Michael, and Winter Storm Diego. In the testimony of witness De May, however, the Company linked its Storm Costs recovery request to the passage of Senate Bill 559 (SB 559) – An Act to Permit Financing for Certain Storm Recovery Costs, and indicated that if that then-pending legislation was enacted by the General Assembly, the Company would seek recovery of its Storm Costs through a securitization filing instead of in base rates.

Witness Jackson detailed DEP's general storm response and recovery systems and procedures. Tr. vol. 11, 61-77. Witness Jackson also described in detail three major storms impacting DEP's system in 2018, Hurricanes Florence and Michael and Winter Storm Diego, as well as a 2019 storm, Hurricane Dorian, along with the Company's responses to these storms and the gross capital investments and O&M expense associated with those responses. *Id*. at 77-103. Witness Jackson testified that the Company's response to the storms, including its restoration efforts, was reasonable and prudent and resulted in the restoration of power to DEP's impacted customers as quickly and safely as was reasonably possible. *Id*. at 102-03.

Witness Smith proposed to recover the incremental cost in excess of normal storm expenses, including a return on the unrecovered balance, and also proposed to begin amortization of the costs when proposed new base rates became effective, and to include a return on the deferred balance through the end of the proposed fifteen-year amortization period. In its Application, DEP's Storm Costs, projected through August 31, 2020, totaled approximately $655.8 million, consisting of approximately $569.2 million in actually incurred or projected storm response O&M costs and approximately $86.6 million in deferred depreciation expense and carrying costs (calculated using the Company's approved weighted average cost of capital) on its actually incurred storm response costs. Witness Smith's second supplemental direct testimony included updated actual amounts of DEP's Storm Costs totaling $714.0 million, consisting of $567.3 million in actually incurred or projected storm response O&M costs, $68.6 million in capital investments, and $78.1 million in carrying costs (calculated using the Company's approved weighted average cost of capital through August 31, 2020).

Public Staff Testimony

Witness Dorgan testified that the Public Staff had reviewed the Storm Costs sought to be recovered in this proceeding and had concluded that they were prudently incurred. Tr. vol. 15, 750. Witness Dorgan also stated that he had made an accounting adjustment to remove these Storm Costs from the rate change request in this docket on the basis of Company witness De May's prior testimony that if the (then pending) storm cost securitization legislation was enacted, DEP would seek to recover its Storm Costs through the alternative securitization mechanism provided by that legislation. *Id*. at 749. Finally, witness Dorgan adjusted DEP's revenue request in the rate case to allow for a ten-year normalization of storm costs not sufficient to support a separate securitization filing. *Id*. at 750.

DEP Rebuttal Testimony

On May 4, 2020, in his Rebuttal Testimony, witness De May indicated that the Company looked forward to pursuing recovery of its Storm Costs through a separate securitization filing but that the Company believed that a determination of the reasonableness and prudence of its Storm Costs should be preserved in the general rate case for determination by the Commission. Tr. vol. 11, 777-78.

Public Staff First Partial Stipulation

In the First Partial Stipulation DEP and the Public Staff agreed to adjustments "to remove the capital and O&M costs associated with the Storms and to reflect a 10-year normalized level of storm expense for storms that would not otherwise be large enough for the Company to securitize." First Partial Stipulation, § III.1. The parties also agreed to a presumptive filing schedule and filing parameters for DEP's securitization filing for its Storm Costs and reserved their respective rights if such filing was not made by the Company. *Id.* at § III.2. Finally, the parties agreed that a storm cost recovery rider should be established for DEP with an initial balance of $0. *Id.* at § III.5.

More specifically regarding the filing schedule, DEP agreed to file a petition for a financing order pursuant to N.C.G.S. § 62-172 no later than 120 days from the issuance of an order by the Commission in this rate case in which the Commission makes findings and conclusions regarding the Storm Costs and the First Partial Stipulation, unless a party in the rate case appeals the Commission's order as it relates to the Storm Costs or the provisions of the First Partial Stipulation related to the Storm Costs and securitization. If an appeal is filed the 120-day limit shall be suspended until the Commission's decision is affirmed or, if not affirmed, until the issuance of a Commission Order on remand following the decision on the appeal, unless the Company chooses before that time to pursue recovery as further described below, in which case the original 120-day limit shall be deemed to have applied. Should DEP fail to file a petition within the time period specified in this paragraph, the parties agreed that, in any subsequent ratemaking proceeding held to provide for recovery of the Storm Costs, the parties reserve the right to assert their respective positions. *Id*. at § III.2.

Regarding the parameters to be followed in the securitization proceeding the parties agreed that to demonstrate quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1) the Company must show that the net present value of the costs to customers using securitization is less than the net present value of the costs that would result under traditional storm cost recovery. For purposes of settlement for the Storm Costs only, the parties agreed to the following assumptions:

(1) For traditional storm cost recovery 12 months of amortization for each Storm was expensed prior to the new rates going into effect;

(2) For traditional storm cost recovery no capital costs incurred due to the Storms during the 12-month period were included in the deferred balance;

(3) For traditional storm cost recovery no carrying charges were accrued on the deferred balance during the 12-month period following the date(s) of the Storm(s);

(4) For traditional cost recovery the amortization period for the Storms is a minimum of fifteen years; and

(5) For securitization the imposition of the Storm recovery charge begins nine months after the new rates go into effect.

Id. at § III.3. The parties further agreed that the amortization of securitized Storm Costs shall not begin until the date the storm recovery bonds are issued. *Id.* at § III.4.

The parties also agreed that a storm cost recovery rider should be established in the rate case and that will be initially set at $0, and if DEP does not file a petition for a financing order or is unable to recover the Storm Costs through N.C.G.S. § 62-172, the Company may request recovery of the Storm Costs from the Commission by filing a petition requesting an adjustment to this rider. *Id.* at § III.5. In such case, DEP and the Public Staff reserve the right to argue their respective positions regarding the appropriate ratemaking treatment for recovering the Storm Costs. *Id*.

Finally, the parties agreed to file a joint petition for rulemaking to establish the standards and procedures that will govern future financing petitions under G.S. § 62-172 upon the issuance of storm recovery bonds for the Storm Costs. *Id.* at § III.6.

No other party provided evidence on DEP's Storm Costs or its storm response and recovery procedures and no party contested the conclusions of the Company and the Public Staff that DEP's Storm Costs were reasonable and prudent.

DEP filed its Storm Costs securitization financing petition with the Commission on October 26, 2020, in Docket No. E-2, Sub 1262.

Discussion and Conclusions

Based upon the evidence and the record, the Commission finds good cause to conclude that DEP's actual costs incurred to respond to and recover from Hurricanes Florence, Michael, Dorian, and Winter Storm Diego, totaling $714.0 million, and consisting of approximately $567.3 million in actually incurred or projected storm response O&M costs, approximately $68.6 million in capital investments, and approximately $78.1 million in carrying costs (calculated using the Company's approved weighted average cost of capital through August 31, 2020), were reasonably and prudently incurred, to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward should remain subject to review in the financing proceeding conducted pursuant to SB 559, or to consideration for recovery in a future general rate case proceeding, pursuant to the provisions of N.C.G.S.§ 62-172(a)(16)(c). Any updates to the deferred Storm Costs projections for storm recovery activities that occurred after the hearings in this docket will be addressed in the securitization proceeding.

The Commission also accepts DEP's decision to remove its Storm Costs from the revenue requirement requested in this proceeding in favor of a separate securitization filing, and the Commission further accepts the fifteen-year normalized adjustment to

DEP's revenue requirement to account for anticipated storm expenses that are not large enough in size to securitize.

The Commission gives substantial weight to the Storm Cost provisions of the First Partial Stipulation and concludes that it is appropriate and consistent with SB 559 that DEP continue to defer its Storm Costs intended to be securitized in a regulatory asset account until the date on which the storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172 or alternative cost recovery is sought by the Company. The amounts recorded in the regulatory asset account will be subject to review by intervening parties and the Commission in the securitization proceeding. Further, it is appropriate and consistent with the statute that DEP continue to accrue and record carrying costs, at the Company's approved weighted average cost of capital, on the deferred balances in its Storm Costs recovery deferred account pending recovery through securitization, again subject to review by intervening parties and the Commission in the securitization proceeding.

The Commission also does not object to the Company using the assumptions the Public Staff and DEP agreed to in the First Partial Stipulation to demonstrate quantifiable benefits to customers, in accordance with N.C.G.S. § 62-172(b)(1). However, the Commission makes no determination in this proceeding as to whether the assumptions and conditions agreed to by the parties are appropriate for use in the calculation of the quantifiable benefits to customers. Instead, the Commission concludes that the appropriateness of the provisions of the First Partial Stipulation regarding the assumptions and methods to be utilized in the demonstration of quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1) are matters to be decided in connection with the Company's joint petition with Duke Energy Carolinas, LLC, for financing orders in Docket No. E-2, Sub 1262 (Securitization Docket). In addition, the Commission accepts the parties' agreement to file a joint petition for rulemaking to establish the standards and procedures that will govern future securitization petitions under N.C.G.S. § 62-172.

The Commission also finds appropriate and reasonable the provisions of the First Partial Stipulation regarding the filing procedure for the securitization proceeding, the agreed-to delay in beginning the amortization of securitized costs, the provisions for establishing a provisional deferral of the storm costs pending the outcome in the securitization docket, and the commitment to pursue a rulemaking proceeding for future securitizations. The Commission concludes that these provisions serve to protect the interests of the Company and its ratepayers.

Finally, the Commission accepts the provision of the First Partial Stipulation to adopt a contingent Storm Cost Recovery Rider, set at $0, as a place holder in the event that securitization of DEP's costs is denied and recognizes that DEP and the Public Staff have reserved their rights to argue their respective positions regarding the appropriate ratemaking treatment for the Storm Costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62-64

Service Regulations, Vegetation Management Reporting Obligations, and Quality of Service

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEP witnesses Pirro and Hatcher, and Public Staff witnesses Floyd, T. Williamson and D. Williamson; and the entire record in this proceeding.

DEP witness Pirro testified to the Company's proposed changes to its service regulations, including: a decrease in the Service Charge from $17.00 to $9.14; a decrease in the Landlord Service Charge from $5.35 to $2.00; a decrease in the Reconnect Charge during normal business hours from $19.00 to $12.94; a decrease in the Reconnect Charge outside of normal business hours from $55.00 to $19.48; an increase in the charge for a customer-requested duplicate meter test for non-demand meters from $40.00 to $45.00; an increase in the charge for a customer-requested duplicate meter test for demand meters from $50.00 to $57.00; and reductions to various other monthly facilities charges. Tr. vol. 11, 1092-93. In addition, the Company proposed to change when bills are considered past due and delinquent for nonresidential customers from 15 to 25 days to match the current requirement for residential customers. *Id*. at 1093.

DEP witness Hatcher provided testimony relating to the Company's service quality and ways in which the Company is working to enhance the customer experience. *Id.* at 840, 858. Witness Hatcher noted that customer satisfaction (CSAT) is a key focus area for DEP. *Id.* at 841. He explained that using data and analytics, the Company is executing a long-term, customer-focused strategy designed to deliver greater value to its customers. The Company's CSAT program includes both national benchmarking studies and proprietary transaction and relationship CSAT studies. *Id.* at 849-50. Witness Hatcher explained that the Company analyzes the results from these studies in vigorous monthly data review sessions, with findings driving improvements to processes, technology, and behaviors – all to continuously improve the customer experience. *Id.* at 850. Specifically, he explained that DEP measures overall customer satisfaction and perceptions about the Company via its proprietary relationship survey, the Customer Experience Monitor Survey (CX Monitor Survey). Surveys are taken from residential, small/medium business customers, and large business customers, to measure customer loyalty and the ongoing perceptions of the customer experience. *Id.* at 850. The CX Monitor Survey data is used to measure the Company's Net Promoter Score (NPS), a top metric used by companies across industries to measure customer advocacy. *Id.* at 841-42. He indicated that since 2018 the Company has seen a significant increase in its NPS, with some of the Company's highest NPS scores occurring between the months of September and December of 2018 was severely impacted by major storms. *Id.* at 851.

Witness Hatcher explained that DEP also utilizes Fastrack 2.0, the Company's proprietary, post-transaction measurement program, to measure overall customer satisfaction with the Company's operational performance. *Id.* Fastrack 2.0 was intentionally designed to complement the CX Monitor survey and provide greater insight into experiences that matter to customers and near real time feedback to front line, customer-facing employees. *Id.* at 851-52. Witness Hatcher explained that analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. *Id*. Through 2018, roughly 85% of DEP residential customers expressed high levels of satisfaction with key service interactions: Start/Transfer Service, Outage/Restoration, and Street Light Repair. Witness Hatcher indicated that the Company has also implemented "Reflect" – a post-contact survey that gathers customers' immediate feedback after contacting Duke Energy by web, text, call to automated system or live agent – to provide feedback. *Id.*

Witness Hatcher further explained that the Company is working hard across its business to further improve the customer experience. *Id*. at 858. Two examples witness Hatcher provided were enhancements to the Company's integrated voice response (IVR) system and the deployment of Customer Connect. Finally, witness Hatcher explained that the Company's efforts to improve customer service is why the Company seeks approval to eliminate convenience fees for credit and debit card payments made by residential customers and to extend the due date for nonresidential to pay their bills from 15 days to 25 days to match the current requirement for residential customers. *Id*. at 862-63.

Public Staff witnesses T. Williamson and D. Williamson testified that the Commission should direct the Company to begin filing semi-annual vegetation management reports in the same manner as DEC files under the Commission's directives in Docket No. E-7, Subs 1146 and 1182. Tr. vol. 15, 354, 362. They explained that there have not been any changes to the vegetation management compliance filing since the Company's March 22, 2016 filing, which are required to be filed with the Commission in Docket No. E-2, Sub 1010. *Id*. at 358.

Witnesses T. Williamson and D. Williamson also testified about DEP's quality of service. *Id*. at 356-58. They reviewed the SAIDI and SAIFI reliability scores filed by DEP in Sub 138A; informal complaints and inquiries from DEP customers received by the Public Staff's Consumer Services Division; the Consumer Statements of Position filed in Docket No. E-2, Sub 1219CS; and the Public Staff's own interactions with DEP and its customers. *Id*. They noted that for the period 2010 through 2019, Company reports show the non-Major Event Days for the SAIDI index have been slowly and moderately worsening over time but staying stable for the SAIFI index. *Id*. The Williamsons concluded that the quality of service provided by DEP to its North Carolina retail customers is adequate.

Public Staff witness Floyd testified that he is generally supportive of the few proposed changes to service regulations discussed by witness Pirro. Tr. vol. 15, 958, 1008.

In Section IV.L of the Second Partial Stipulation DEP and the Public Staff agreed that the Commission should require the Company to file an annual report of its vegetation management performance similar to the DEC's report format filed in Docket No. E-7, Subs 1146 and 1182. In Section IV.N DEP and the Public Staff agreed that the Company's quality of service is good.

No other party offered any evidence addressing these issues. The Commission therefore finds and concludes that the amendments proposed by the Company to its service regulations and the above-discussed provisions of the Second Partial Stipulation are supported by substantial evidence and are just and reasonable to all parties to this proceeding. Therefore, given the record evidence and consistent with the Second Partial Stipulation, the Commission finds and concludes that (1) the proposed amendments to DEP's Service Regulations shall be, and are hereby, approved; (2) the Company shall file an annual report of its vegetation management performance similar to the DEC's report format filed in Docket No. E-7, Subs 1146 and 1182; and (3) the overall quality of electric service provided by DEP is good.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-67

AMI and Green Button Connect

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEP witnesses Schneider and Pirro, and Public Staff witness Floyd; and the entire record in this proceeding.

Summary of the Evidence

DEP Witness Schneider testified that as of August 2019 DEP had installed approximately 723,000 AMI meters in its North Carolina service territory. He stated that DEP plans to continue AMI implementation through early 2021 to finish installing the remaining approximately 694,000 AMI meters. He further stated that DEP began enrolling customers in its AMI opt-out Manually Read Meter (MRM) program in April 2019, and that through August 2019 about 0.16% of DEP's customers [1,105] opted out of receiving a smart meter. Tr. vol. 11, 946-47. Witness Schneider testified that since DEP's last rate case and through June 30, 2019, the Company invested $158.3 million in AMI on a system basis, and that DEP projected that it would invest $53.3 million from July 1, 2019, through February 29, 2020. *Id.* at 947-48.

Witness Schneider further testified to the benefits of AMI, including customer access to more usage information, speedier storm outage detection and restoration, more flexibility in customer billing dates, time-of-use rate designs, and Usage Alerts at the mid-point of the customer's billing cycle. *Id.* at 948-52.

DEP Witness Pirro testified that the costs of opting out of an AMI meter could justify an increase in the MRM one-time setup fee from $170 to $180.52, and the recurring monthly fee from $14.75 to $20.75. However, DEP is not requesting to increase these fees. Witness Pirro stated that these fees have been in effect for less than a year and it would be premature to adjust them at this time. He further testified that as of August 1, 2019, there were 938 DEP customers who had requested the MRM option, and that 551 of those customers provided medical forms to have the MRM fees waived. Tr. vol. 11, 1110.

Witness Pirro also testified that DEP proposes to decrease its service connection charge from $17 to $9.14 and the reconnection charge from $19 to $12.94 during normal business hours, and from $55 to $19.48 outside of normal business hours. He stated that these reductions are based on the savings resulting from the Company no longer having to dispatch its personnel to the customer's location to perform connections and reconnections. *Id.* at 1092.

Public Staff witness Floyd testified that the Public Staff agrees with DEP's decision not to increase the MRM fees at this time. He also noted that DEP has enrolled 667 customers who qualified for the medical waiver of opt-out fees. He stated that the Public Staff believes that AMI opt-out costs that are not recovered from participants should be recovered from all DEP customers. Tr. vol. 15, Part 2, 963-66. Witness Floyd further testified that he reviewed DEP's cost calculations for the reductions in connection and disconnection charges proposed by DEP witness Pirro and that these changes are supported by the Company's calculations. *Id.* at 966.

Finally, witness Floyd testified that DEP is not presently using AMI data to develop new rate designs. He stated that this is because the Company's AMI deployment is only about 60% complete. He further stated that the Public Staff believes that as soon as practicable DEP should begin incorporating AMI data into its load research supporting both rate design and integrated resource planning and sharing and comparing its findings from the AMI data with DEC. *Id.* at 966-67.

In Section IV.H of the Second Partial Stipulation DEP and the Public Staff agreed that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEP customers, and that the current MRM charges provide a reasonable hurdle to discourage a customer from opting out of AMI metering without a legitimate reason.

In its post-hearing brief the AGO contended that DEP's cost of implementing AMI is excessive relative to the benefits that are being offered by DEP. The AGO also stated that DEP plans to integrate AMI meters with its Customer Connect billing platform using My Duke Data Download, characterized by the AGO as a nonstandard, outdated technology. The AGO stated that DEP modeled its billing platform on older technology called Green Button Download that has more limited capabilities than the standard technology now available. The AGO maintained that DEP should be required to file revised Customer Connect plans that incorporate Green Button, or another similarly advanced standard technology, or, if that is not possible, DEP should be directed to propose an alternative plan for providing comparable access to customers. AGO Brief, at 127-30.

Discussion and Conclusions

The testimony of DEP witnesses Schneider and Pirro, as well as Public Staff witness Floyd, provides substantial evidence that DEP has deployed its AMI meters in a prudent manner and that the costs of such deployment are reasonable. Moreover, the testimony and the Second Partial Stipulation provide substantial evidence that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEP customers.

The Commission is not persuaded by the AGO's contention that DEP should be ordered to implement Green Button. The Commission has an ongoing investigation and rulemaking in Docket No. E-100, Sub 161 to address the subject of customer and third-party access to electric usage data. Numerous parties, including the AGO, have filed comments and proposed rules, some of which include guidelines for the possible role of Green Button.

Based on the foregoing, the Commission concludes that DEP should be allowed to recover its costs of AMI deployment, and that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEP customers. Further, the Commission concludes that it should not require DEP to incorporate Green Button into its Customer Connect billing system at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 68

Focal Point Project Costs

Public staff witness Metz recommended that the capital costs related to the Focal Point Project be removed from rate base. Tr. vol. 15, 859. Witness Metz testified that Focal Point is a corporate-wide initiative to replace and upgrade older monitoring and recording equipment (e.g., cameras) with modern, state of the art equipment. He noted that once this upgrade is complete it is intended to be an overall upgrade to Duke Energy Corporation's security system. Witness Metz testified that he recommended removal of these costs because these costs were for equipment that is not fully installed and operational. Witness Metz recommended a total system cost adjustment of approximately $3 million. He stated that these should be sought for cost recovery once installed. He further noted that DEP agreed to not request cost recovery in this proceeding.

Witness Metz testified that both of his adjustments had been incorporated into the schedules and exhibits presented by Public Staff witness Maness.

In light of the evidence presented in this proceeding, the Commission finds and concludes that the adjustments to remove the costs associated Focal Point are appropriate and just. Both DEP and the Public Staff agreed that the costs related to Focal Point should be removed from rate base in the current proceeding. The Commission does not yet consider these costs ripe for cost recovery, given that they are for equipment that is not installed or operational. Accordingly, the Commission concludes that these costs should be removed from rate base at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69

Roxboro Wastewater Treatment Plant Deferral

In its Application and the direct testimony of DEP witness Smith, the Company requested an accounting order to establish a regulatory asset to defer the unrecovered net book value of its Roxboro Wastewater Treatment Plant at the time of the plant's anticipated early retirement in 2021. Application at 19; Tr. vol. 13, 165. The Company requested to amortize the costs, the remaining net book value of the plant at the time of its retirement, at the level presented in the proposed depreciation study until rates can be adjusted in the Company's next rate case. *Id.* The Company also requested permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. *Id.*

No party contested the Company's request for an accounting order.

Based upon all the evidence presenting in this proceeding, the Commission finds and concludes that the Company's request for an accounting order for the Roxboro Wastewater Treatment Plant is reasonable and approved and the Company is authorized to amortize the costs at the level approved by the Commission in this proceeding for the applicable depreciable plant in service accounts, subject to further changes in the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

Accounting for Deferred Costs

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In the present case, the Commission is approving DEP's recovery through amortization of a previously deferred portion of DEP's CCR costs. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. As a result, a deferred cost is not the same as other cost of service expenses to be recovered in the Company's non-fuel base rates and, therefore, should be subject to different accounting guidelines.

When the Commission approves a typical cost of service, such as salaries and depreciation expense there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, with respect to deferral of costs already incurred, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account rather than a general revenue account. If DEP continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DEP is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 71

Just and Reasonable Rates

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of the Evidence

As previously discussed, pursuant to N.C.G.S. § 62-133(a) the Commission is required to set rates that are "fair both to the public utilities and to the consumer." To strike this balance, the Commission must consider, among other factors: (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers; and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. N.C.G.S. § 62-133(b). DEP's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DEP's individual customers, as well as the communities and businesses served by DEP. The Company presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

DEP witness De May testified that the Company is experiencing significant changes throughout many aspects of the electric industry, and that the investments it has made and must continue to make are designed to keep pace with evolving customer needs and expectations. Tr. vol. 11, 753. He explained that reliability remains essential as an increasingly connected population continues to expand, especially in the urban areas of North Carolina. *Id*. Witness De May also testified that the energy sector is in a period of transformation and profound change driven by technological advancements, environmental mandates, storm activity and response, energy security and resiliency efforts, as well as changing customer expectations. *Id.* at 753. As one example, he stated that DEP's customers want more information about how they consume energy and more tools that help them manage their consumption. According to witness De May, DEP is responding by investing in a more efficient distribution grid, AMI meters, and cleaner and more efficient generation units. In addition, witness De May stated that DEP is actively working toward achieving a lower carbon future by taking steps to reduce its reliance on coal-fired generation. *Id.* at 755.

Moreover, witness De May further outlined how the Company is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during periods of financial hardship. *Id.* at 818 He outlined assistance programs the Company offers to help customers reduce their energy costs such as the Company's portfolio of demand-side management and energy efficiency programs, including the Neighborhood Energy Saver Program. *Id.* Indeed, as part of the Public Staff Partial Stipulations, DEP will make shareholder-funded contributions, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC, of a combined $3 million per year for two years to the Helping Home Fund, for a total of $6 million. Further, DEP will make an annual $2.5 million shareholder-funded contribution to the Energy Neighbor Fund in 2021 and 2022, for a total contribution of $5 million.

Witness De May and other witnesses described the importance of DEP's maintaining a strong financial position in order to facilitate the Company's investments in utility service infrastructure. *Id.* at 760; *see also* tr. vol. 1, 54; tr. vol. 3, 39. He stated that the Company's strong financial position and performance benefit customers by reducing DEP's cost of borrowing and cost of attracting equity capital. As previously discussed, the Commission does not set rates based on DEP's credit metrics. Rather, the Company's credit ratings and other credit metrics are the responsibility of the Company to manage. Nonetheless, the Commission has considered the evidence on potential credit impacts and given that evidence due weight as a part of the Commission's ratemaking task that requires the Commission to set rates that are fair to DEP and its ratepayers. N.C.G.S. § 62-133. The utility's access to credit at a reasonable cost is important to both DEP and its ratepayers. Both benefit if the Company can obtain credit at the best interest rates reasonably possible. The Commission concludes that the rates set herein achieve the appropriate balance of being credit supportive for DEP and fair to its ratepayers.

Witness De May also detailed how the Company is actively working toward achieving a lower carbon future by taking steps to close the final chapters on coal ash and reducing its reliance on coal-fired generation *Id*. at 755. He testified that the Company is investing in natural gas and solar, including the Company's addition of a new combined-cycle natural gas facility at Asheville and that as part of the Company's strategy to reduce its reliance on coal DEP has taken a fresh look at the viability of several of its coal-fired plants. *Id.* at 755-56. He added that the Company's high performing nuclear fleet has and will continue to provide North Carolina carbon free generation now and into the future. *Id.* at 756. For example, in 2018 DEP's nuclear fleet achieved an 88.58% capacity factor, despite significant challenges attributable to the landfall of hurricane Florence. *Id.* at 854.

DEP witness Turner described the Company's fossil/hydro/solar (FHO) generation assets and provided operational performance results for those assets during the test period. Tr. vol. 11, 970-71, 975-77. Witness Turner testified to the major FHO capital additions DEP has completed since the previous rate case, explaining that the Company has made significant investments in the coal fleet to meet environmental regulations to allow for the continued operation of active plants. *Id.* at 972. Witness Turner also discussed the addition of the Asheville CC Project units, and the retirement of the two Asheville Steam Electric Generating Plant units, anticipated by the end of 2019. In addition, she explained that the Asheville CC Project, for which DEP received a certificate of public convenience and necessity (CPCN) from the Commission in the Asheville CPCN Order, features state-of-the-art technology for increased efficiency and reduced emissions. *Id*. at 971-72.

Witness Schneider testified to DEP's installation of approximately 723,000 AMI meters in its North Carolina service territory as of August 2019, and its planned continued implementation through early 2021 for the remaining approximately 694,000 AMI meters. *Id*. at 947. Witness Schneider noted that since DEP's last rate case through June 30, 2019, the Company invested $158.3 million on new AMI meters across the system in North and South Carolina, and that the Company projected to invest an additional $53.3 million across the system between July 1, 2019, through February 29, 2020. *Id.* at 948. In addition, he testified to the customer benefits of AMI, including lower cost O&M due to remote disconnections and reconnections, customer access to more usage information, speedier storm outage detection and restoration, more flexibility in customer billing dates, and new time-of-use rate designs.

These are representative examples of the capital investments that have been made and are planned by DEP in order to continue providing safe, reliable, and efficient electric service to its customers. In this time of COVID-19 with many people working and schooling at home, the importance of safe, reliable, and efficient electric service is heightened beyond its normal level as an essential service.

Discussion and Conclusions

Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DEP's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DEP in maintaining the Company's financial strength at a level that enables the Company to obtain sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of the Act and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 72

Revenue Requirement

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations; the testimony and exhibits of the witnesses, including DEP witness Smith and Public Staff witness Maness; and the entire record in this proceeding.

The First and Second Partial Stipulations between the Company and the Public Staff provide for certain accounting adjustments that the Company and the Public Staff have agreed upon and the Commission has approved in this Order. The stipulated issues on revenue requirement effects are detailed in Smith Second Settlement Exhibit 3, Maness Stipulation Exhibit 1, Schedule 1, and Maness Second Stipulation Exhibit 1, Schedule 1, which provide sufficient support for the annual revenue required on the issues agreed to in the Second Partial Stipulation.

The Company's calculation of the revenue requirement impact of the issues settled in the Second Partial Stipulation is an increase in the base revenue requirement of approximately $19,495,000, to be further adjusted by the Public Staff's recommendations in its testimony filed on September 15 and 16, 2020. Maness Second Supplemental and Stipulation Exhibit 1 reflects the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Second Partial Stipulation as well as the Public Staff's position on the remaining unresolved issues. The total impact on the base revenue requirement of the Public Staff's Second Partial Stipulation settled items is reflected on Maness Second Stipulation Ex. 1.

As discussed in the body of this Order, the Commission approves portions of the stipulations and makes its individual rulings on the unresolved issues. Due to the intricate and complex nature of some of the issues, the Commission concludes that DEP should recalculate the required annual revenue requirement consistent with the Commission's findings and rulings herein within 10 days of the issuance of this Order. The Commission further concludes that DEP should work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an Order with final revenue requirement numbers.

IT IS, THEREFORE, ORDERED as follows:

1. That the approved base fuel and fuel-related cost factors by customer class are as follows: 2.080 cents/kWh for the Residential class, 2.126 cents/kWh for the Small General Service class, 2.228 cents/kWh for the Medium General Service class, 2.204 cents/kWh for the Large General Service class, and 1.392 cents/kWh for the Lighting class;

2. That DEP shall use of a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs;

3. That DEP shall use its proposed future net salvage for mass property Accounts 364, 366, and 369;

4. That DEP shall use an average service life of 15 years for new AMI meters being deployed;

5. That DEP shall continue to use a 20-year amortization period for Accounts 391 and 397;

6. That the depreciation rates proposed by DEP in this case are approved, except as specifically modified by this Order;

7. That the depreciation rate for the Mayo Unit 1 and Roxboro Units 3 and 4 generating plants shall not be changed, and shall be based upon the remaining life of the plants, as approved in DEP's rate case in Docket No E-2, Sub 1142;

8. That upon actual retirement of each generating unit, Mayo Unit 1 and Roxboro Units 3 and 4, the remaining net book value shall be placed in a regulatory asset account to be amortized over an appropriate period to be determined in a future rate case;

9. That DEP's costs of capital investments in its coal fleet to meet environmental regulations to allow for the continued operation of active coal units shall be included for recovery in DEP's rates;

10. That the costs related to the Company's capital investments in its nuclear generation fleet shall be included for recovery in DEP's rates;

11. That the stipulations of DEP with the Public Staff, CIGFUR, Harris Teeter, Commercial Group, Vote Solar, and jointly with NCSEA and NCJC et al. are accepted and approved in part, as detailed in this Order;

12. That DEP shall recover the balance of its deferred CCR costs reduced by $261 million in the present case and shall cease to accrue financing costs on this amount as of December 31, 2020, consistent with the CCR Settlement; and that DEP shall recover the balance of its deferred CCR costs over a five-year amortization period with reduced financing costs during the amortization period calculated based on (1) DEP's cost of debt set forth in the Second Partial Stipulation, adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.60% ROE set forth in the Second Partial Stipulation, and (3) a capital structure of 48% debt and 52% equity set forth in the Second Partial Stipulation;

13. That DEP is authorized to record its March 1, 2020, and future CCR costs in a deferred account until its next general rate case; that this deferral account will accrue a return at the overall rate of return approved in this Order consistent with the CCR Settlement;

14. That the agreed-upon accounting adjustments outlined in Smith Partial Settlement Exhibit 3, Smith Second Settlement Exhibit 3, Maness Stipulation Exhibit 1, Schedule 1, and Maness Second Stipulation Exhibit 1, Schedule 1 shall be, and are hereby, approved;

15. That the Company's revised Lead-Lag Study filed as Angers Supplemental Exhibit 3 shall be, and is hereby, approved for purposes of calculating the cash working capital amounts to be included in the Company's revised rates;

16. That DEP's request for an accounting order for approval to establish a regulatory asset to defer the North Carolina retail portion of incremental O&M expenses associated with the Company's severance program, as modified by the terms of the First Partial Stipulation, shall be, and is hereby, approved;

17. That DEP shall reduce the annual funding for the Company's Nuclear Decommissioning Trust Fund by $8.7 million;

18. That the Company's request to defer the costs related to the Asheville CC Project, as modified by the terms of the First Partial Stipulation, is approved;

19. That DEP's request for deferral accounting for GIP expenditures is approved consistent with its Second Partial Stipulation with the Public Staff and subject to the conditions set forth in this Order;

20. That DEP shall work expeditiously with the Public Staff to refine its GIP reporting requirements, as intended under the Second Partial Stipulation, and file the first report for spending during the last half of 2020 by June 1, 2021;

21. That in its next general rate case DEP shall file a proposal for moving all DSDR and CVR costs into base rates;

22. That by August 1, 2021, DEP shall file in Docket Nos. E-100, Sub 165 and E-2, Sub 926 information regarding the cost of replacing peaking capacity lost due to the DSDR-to-CVR conversion;

23. That the proposed RAL-1 Rider is approved and shall be implemented;

24. That DEP's proposed revision to its previously approved North Carolina EDIT rider (EDIT-1) to reflect the change in the federal corporate income tax rate from 35% to 21%, is just and reasonable and shall be, and is hereby, approved;

25. That the proposed EDIT Rider, as modified by the terms of the DEP and Public Staff Partial Stipulations, is approved and shall be implemented; that the protected federal EDIT will be removed from the EDIT Rider and returned to customers through base rates;

26. That the agreement between DEP and the Public Staff as outlined in the Second Partial Stipulation concerning how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate, which may occur during the respective amortization periods, is hereby approved;

27. That the CIGFUR Stipulation allowing EDIT and the provisional revenues to be flowed back based on a uniform cents per kWh basis is inappropriate and is hereby not approved;

28. That all federal unprotected EDIT and provisional revenues shall be flowed back based on the amounts each rate class paid, as recommended by Public Staff witness Floyd;

29. That the jurisdictional and class cost allocation methodologies proposed by the Company are approved and shall be implemented;

30. That the aspects of rate design agreed upon in the Second Partial Stipulation are approved and shall be implemented;

31. That the Company's proposed modifications of certain outdoor lighting fees and schedules are approved;

32. That the Basic Customer Charges as set forth in Pirro Exhibit 7 are approved;

33. That the Company's proposed structure and pricing for Schedule LGS-RTP, as modified by the Commission's final determination of revenue requirement, should be approved;

34. That the SGS-TOU rate provisions agreed upon in the Harris Teeter and Commercial Group Stipulations are approved and shall be implemented;

35. That the LGS rate provisions agreed upon in the CIGFUR Stipulation are approved and shall be implemented;

36. That the rates for the CSE and CSG rate schedules shall be adjusted to affect a gradual movement in aligning rates with costs consistent with the guidance detailed above;

37. That the Company shall conduct a comprehensive Rate Design Study as outlined in the Public Staff Second Partial Stipulation and further described herein with broad stakeholder engagement facilitated by a third party to be engaged by the Company; that the Company shall initiate the Rate Design Study with stakeholders no later than 30 days following the date of this Order; that the Company shall file quarterly status reports in this docket detailing the work of the Rate Design Study participants; and that the Company shall file a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study within 12 months of the date of this Order;

38. That the Company shall convene a stakeholder process that is tasked with addressing affordability issues for low-income residential customers consistent with the terms of this Order;

39. That DEP, in conjunction with the concurrent commitment of Duke Energy Carolinas, LLC, shall make an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million);

40. That DEP shall make an annual $2.5 million shareholder-funded contribution to the Energy Neighbor Fund in 2021 and 2022, for a total contribution of $5 million;

41. That the Company's Storm Costs are reasonable and prudent;

42. That the terms of the Public Staff First Partial Stipulation providing for a contingent Storm Cost Recovery Rider set at $0 are approved;

43. That DEP's request to defer the Storm Costs in a regulatory asset account until the date that storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or until the Company seeks recovery of the Storm Costs through an alternative method of cost recovery, is hereby approved;

44. That the Company shall conduct an independent review and audit of its M&S inventory, to be performed by the Company's internal Corporate Audit Services department, and as further described in the Public Staff Second Partial Stipulation;

45. That within 90 days of this Order, the Company and the Public Staff shall begin collaborations on document retention, project reporting, and other reasonably applicable matters to better assist the Public Staff in future audits of plant;

46. That the Company and the Public Staff shall meet to discuss the Company's plant unitization policies and reporting obligations;

47. That the proposed amendments to DEP's Service Regulations shall be, and are hereby, approved;

48. That the Company shall file an annual report of its vegetation management performance similar to the DEC's report format provided in Docket No. E-7, Subs 1146 and 1182;

49. That DEP shall recover its costs of deploying AMI meters;

50. That DEP shall recover its Rider MRM costs that are not recovered from customers opting out of AMI meters from all DEP customers;

51. That DEP shall remove the costs associated with the Focal Point Project from rate base;

52. That DEP's request for an accounting order to establish a regulatory asset to defer the remaining net book value of the Roxboro Wastewater Treatment Plant, at the time of the plant's anticipated early retirement in 2021, and costs related to obsolete inventory, net of salvage, at the time of retirement is approved and the Company may continue amortizing the costs at the level approved by the Commission in this proceeding for the applicable plant in service accounts, and subject to further changes in the Company's next general rate case;

53. That if DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case;

54. That DEP shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company shall work with the Public Staff to verify the accuracy of the filing; and

55. That DEP shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) with the Commission within 10 days of the issuance of this Order, summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

ISSUED BY ORDER OF THE COMMISSION.

This the 16th day of April, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

Commissioner ToNola D. Brown-Bland dissents in part.
Commissioner Daniel G. Clodfelter dissents in part.
Commissioner Floyd B. McKissick dissents in part and concurs in part

Commissioner ToNola D. Brown-Bland, dissenting in part:

I dissent from the Commission's decision to allow the Company to defer the capital costs of eight programs associated with GIP investments and to accept and approve the Second Partial Stipulation as it relates to said investments.

In my opinion, the majority decision on GIP cost deferral is contrary to the ratemaking standards of N.C. Gen. Stat. § 62-133. Use of deferral accounting is generally outside the traditional principles set forth in N.C.G.S. § 62-133(b) and (c), and therefore can only be allowed pursuant to N.C.G.S. § 62-133(d). However, the greater weight of the record evidence compels the determination that the cost items for which deferral is sought — and agreed upon by fewer than all parties of record — are not so unusual, extraordinary, or complex that the Company should be granted an exception to seek recovery of costs outside of the ordinary ratemaking standards established by the General Assembly; nor has the majority made any such finding. I cannot agree that the parties' settlement of this issue overrides or obviates the Commission's duty to make the determinations that are *required* before deferral accounting can be authorized under Chapter 62 of the North Carolina Utilities Act. *State ex rel. Utils. Comm'n v. Stein,* 375 N.C. 870, 926, 851 S.E.2d 237, 273 (2020).

In N.C.G.S. § 62-133(d), the legislature saw fit to provide both consumers of public utility service and public utilities with a "'safety valve'" which permits the Commission to consider facts outside of those prescribed by the ordinary ratemaking standards when those standards "prove inadequate" to allow the Commission to meet its obligation to set just and reasonable rates. *Id.* at 925-26, 851 S.E.2d at 272–73. Our Supreme Court recently clarified, however, that § 62-133(d), the safety valve, is to be relied upon over § 62-133(b) and (c) only "in extraordinary instances in which the traditional ratemaking standards set forth in N.C.G.S. § 62-133 are insufficient." *Id*. That is to say, N.C.G.S. § 62-133(d) is not to be exercised routinely.

To the contrary, "N.C.G.S. § 62-133(d) [does] not allow the Commission to . . . ignore the ordinary ratemaking standards set out elsewhere in N.C.G.S. § 62-133" where use of those principles allows for the establishment of just and reasonable rates. *Id.* at 926, 851 S.E.2d at 273. The "safety valve" is just that, and cannot be applied absent specific determinations of "unusual, extraordinary, or complex circumstances" unable to be addressed by traditional ratemaking standards. In relying on the safety valve, the Commission must reasonably conclude that such circumstances justify a departure from traditional standards, determine that the facts establishing those circumstances must be considered in order to set just and reasonable rates, and provide sufficient explanation as to why divergence from traditional standards is appropriate. *Id.* Such determinations and conclusions are decidedly absent from the majority decision.

In practice, the Commission has long applied virtually the same factors articulated by the Supreme Court in *Stein* before exercising its discretion pursuant to N.C.G.S.

§ 62 133(d) to allow public utilities to recover costs using deferral accounting. The Commission has repeatedly stated that deferral accounting is the exception to the general rule that costs should be recovered from ratepayers and applied to or matched with revenues received during the same time period the costs were incurred; is contrary to the rule; should be used sparingly; and is not favored as it provides for the future recovery of costs for utility services provided to ratepayers in the past. *See* Order Approving Deferral Accounting with Conditions, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred*, No. E-7, Sub 874, at 24–25 (N.C.U.C. Mar. 31, 2009).[1] As a result, the Commission consistently requires utilities requesting deferral treatment to make a clear and convincing showing that the costs proposed for deferral are of an unusual or an extraordinary nature or type and that, absent deferral, the requesting utility would experience a negative material impact on its financial condition. *Id.* This requirement ordinarily demands a showing that such costs represent significant, considerably complex, nonroutine investments that were unanticipated or beyond the utility's ability to control or plan for the timing of incurring the costs. *See* Order Granting Partial Rate Increase, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer*, Docket No. W-354, Sub 364, at 42-43 (N.C.U.C. March 31, 2020). If the cost items sought to be deferred are not found to be unusual or extraordinary, such determination is dispositive and the materiality of the impact of the costs on the financial condition of the utility is not reached. *See* Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Elec. & Power Co., d/b/a Dominion N.C. Power, for Approval of Amended Schedule NS*, No. E-22, Sub 517, at 11 (N.C.U.C. Mar. 29, 2016) (Sub 517 Order).

In this case, as in Duke Energy Carolina, LLC's (DEC) last two rate cases, the items proposed for deferral fail the unusual and extraordinary inquiry. In DEC's 2018 general rate case, it proposed to recover costs using deferral accounting for a modernization project it called Power Forward. I agree with Commissioner Clodfelter that GIP, as presented in both the instant case and DEC's 2020 general rate case, is primarily a subset, or a whittled down, more compact version, of Power Forward — in its scope, size, and costs.[2] The eight GIP programs that the Public Staff and DEP stipulate as

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[1] *See also* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, and Requiring Customer Notice, *Application of Aqua North Carolina, Inc. to Adjust and Increase All rates for Water and Sewer Utility Service,* No. W-218, Sub 526, at 41–47, 136-37 (N.C.U.C. October 26, 2020); Order Allowing Deferral Accounting, *Transfer of Certificates of Pub. Convenience and Necessity and Ownership Interests in Generating Facilities from Duke Energy Carolinas, LLC, to Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC*, No. E-7, Sub 1181, at 16–18 (N.C.U.C. June 5, 2019); Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Aqua N.C., Inc., for Authority to Adjust and Increase Rates*, No. W-218, Sub 497, at 50 (N.C.U.C. Dec. 18, 2018); Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Elec. & Power Co., d/b/a Dominion N.C. Power, for Approval of Amended Schedule NS*, No. E-22, Sub 517, at 11–12 (N.C.U.C. Mar. 29, 2016); Order Approving Deferred Accounting Treatment, *Request by Pub. Serv. Co. of N.C., Inc., for Deferred Accounting Treatment Related to Year 2000 Conversion Costs*, No. G-5, Sub 369, 3–4 (N.C.U.C. Apr. 29, 1997), *aff'd*, Order on Reconsideration (N.C.U.C. June 12, 1997).

[2] While DEP did not include Power Forward in its revenue requirements for the Sub 1142 proceeding, as part of its Sub 1142 testimony describing its own Power Forward initiative, DEP targeted

appropriate for deferral treatment are not at all extraordinary or unusual. Neither the GIP programs nor the reasons proffered for their need, as was the case with the programs in Power Forward, are unique or extraordinary to DEP or North Carolina. Rather the GIP programs are update, upgrade, and modernization programs, required of the Company to maintain the electrical distribution system and improve reliability, and are part of the routine, ordinary business of being a vertically integrated electricity provider. Without such programs the electric utility would not be providing quality service.

Further, these requirements are not new to the industry, and it cannot be said that the Company was unaware and unable to plan and time the recovery of the modernization projects approved by the Commission as part of GIP. Instead, a review of DEP's and its parent company's Annual Reports reveals that both the Company and its parent have been discussing and planning for grid modification initiatives for a long time. Unlike a catastrophic storm that develops with little notice or warning, the need for grid modification is such a routine circumstance that the Company has discussed and worked on related plans for over ten years. In 2010, the parent company discussed graduating its grid from analog to digital and adding two-way communications capabilities to its system to improve reliability and better serve customers. As early as 2007, DEP was already investing in its Distribution System Demand Response program (DSDR), an improvement to its distribution system allowing the utility to manage voltage on its entire distribution system. DSDR[3] will essentially be converted to become part of IVVC, one of the GIP programs approved in this docket by the majority for deferral, and it illustrates that such voltage control initiatives are not new. Well before the Power Forward and GIP proposals, voltage control projects like DSDR and IVVC had been considered part of the business of maintaining and operating a reliable, efficient electrical distribution system. Such projects have never been considered unusual or beyond the context of maintaining the grid to provide quality service. Thus, Commissioner Clodfelter is correct in noting that the Company has been investing in grid modification and some of the proposed GIP programs over several years further highlighting that this work is a regular part of the Company business and, more importantly, that traditional ratemaking procedures have been adequate. To this day, all decisions as to timing, pace, and amount of spending on grid modification have been largely within the Company's control — again, undermining any finding of extraordinary circumstances that might justify deferral accounting as a means of cost recovery for GIP.

I do not disagree with the proposition that GIP will provide benefits or that the Company's initial GIP proposal has been narrowed, focused, and vetted by stakeholders, including the Public Staff, who have worked together and invested time in coming to agreement and refining DEP's GIP proposals. I also believe that it is wise, given so much uncertainty around the cost estimates for GIP, that the Commission is limiting costs and

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that it intended to spend $1.6 billion in capital and $62.4 million in O&M from 2017 through 2021. *See* 2018 Tr. vol. 6, 59–60; 2018 Tr. vol. 9, 22.

[3] DSDR was approved by the Commission for DSM/EE rider cost recovery in 2009. Order Approving Program, *Petition of Progress Energy Carolinas, Inc. for Approval of Distribution System Demand Response Program,* Docket No. E-2, Sub 926, (N.C.U.C. June 15, 2009).

that the Public Staff will work with the Company to file reports and cost trackers on various details of GIP progress. Yet, none of these considerations establishes that GIP is extraordinary or unusual such that the Company should be allowed to depart from the ordinary ratemaking procedures in § 62-133. Unlike in cases concerning disputes and interests limited to private parties where settlements are generally favored, the Commission should refrain from treading down the path that could suggest that parties will be allowed through settlement to disregard law and clearly established Commission principles of regulation, especially where such settlements affect the public interest protected by the law and principles at issue as well as the interests of the non-settling parties.

It is my further opinion that parties in this proceeding have misconstrued the language in the Commission's opinion in the 2018 DEC Rate Order. There, the Commission stated the following:

> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the "extraordinary expenditure" test.

2018 DEC Rate Order, at 149. This language does not signal any change to the Commission's historical test for deferral accounting; rather, it speaks to a realization that single-issue ratemaking concerns implicated by authorization of deferral accounting could be lessened by the full contemporaneous review of all costs and revenues that occurs as part of a general rate case. Therefore, the Commission suggested that it had the future option to revise or create a different deferral test for a deferral request made and considered as part of a general rate case. No such change was made in that Order and no such change has been made by this Commission since that time. The test remains unchanged and continues to require a finding of extraordinary and unusual circumstances in order to approve deferral accounting such as requested for GIP. Indeed, given the *Stein* decision it is not clear that the Commission *could* craft any test changing or eliminating the extraordinary and unusual requirement even if it wants.

Moreover, the second sentence in the passage above relates to a deferral request made outside a general rate case. It is not meant to convey the demise of the primary focus of the historical deferral test, *i.e.*, the extraordinary and unusual circumstance. *See also* Sub 517 Order, at 11 (explaining that the unusual or extraordinary determination is the primary hurdle for deferral approval). Rather, it addresses the secondary materiality/magnitude aspect of the test in the event that the utility was to seek deferral prior to, and outside of, a general rate case. In that circumstance, the referenced leniency was to be directed to the "extraordinary *expenditure"* threshold only — not directed to the extraordinary or unusual circumstance aspect of the test, which is required by the Supreme Court in *Stein* for the exercise of the Commission's authority pursuant to § 62-133(d).

Finally, like all utilities whose rates for service are set by the Commission, DEP abhors regulatory lag and has from time to time made attempts to eliminate or reduce it by use of the deferral mechanism. However, some lag is an inherent part of the statutory ratemaking process in North Carolina — and has been for decades. While regulatory lag in rates offers some positive aspects to customers – e.g., serving as incentive for cost effective and efficient management of the utility and also serving as a guard against waste and inefficiency — it is understandable that utilities see it as a challenge. If regulatory lag is indeed the driving force behind the request for deferral treatment of GIP costs, the appropriate solution is legislative relief. The Commission should not strain the bounds of its authority to exercise use of a deferral mechanism where the legislature did not intend it to be used.

For these reasons I respectfully dissent.

/s/ Commissioner ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

Commissioner Daniel G. Clodfelter, dissenting in part:

I differ from the Commission Opinion on three points and therefore write separately to explain my reasons for doing so.[1]

I. Deferral of Grid Improvement Plan Capital Costs

Deferral accounting is an exception to the basic principle embodied in N.C.G.S. § 62-133 that costs are to be allocated and charged to the revenues received in the period during which expenditures were incurred. *State ex rel. Utilities Commission v. Edmisten,* 291 N.C. 451, 468-70, 232 S.E.2d 184, 194-96; *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 921, 851 S.E.2d 237, 269-70 (2020) (*Stein*).

For this reason the Commission has established a clear standard for granting deferral accounting treatment. I believe the Commission addresses this standard only in the most cursory fashion and does not properly consider its application to this case. The discussion of the standard for deferral accounting in the Commission's opinion at page 140 is limited to noting that in the Sub 1146 Order the Commission stated that deferral accounting could be granted under different parameters in a general rate case than when the request was made outside a general rate case. But neither the Sub 1146 Order nor the Commission's order in this case attempt to articulate what those "different parameters" are or might be or under what circumstances a departure from the generally prevailing standard is warranted. Moreover, as noted elsewhere in this dissent, the Commission has regularly applied its established test for deferral accounting *in general rate cases,* including in Docket No. E-7, Sub 1146 and the other Commission decisions cited and quoted in this dissent. I find the Commission's treatment of the matter in this case to be essentially standardless.

As recently as its March 31, 2020 Order Granting Partial Rate Increase and Requiring Customer Notice in Docket No. W-354, Sub 363 (CWSNC Order) the Commission reiterated that deferral accounting should be used sparingly and as an exception to the general rule that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality in determining the appropriateness of a utility's rates and charges. Paraphrasing from the CWSNC Order, deferral is not favored in part because it provides for the future recovery of costs for utility services that were provided to ratepayers in the past. The Commission has found that an exception can be made when reasonable and prudently incurred costs are unusual or extraordinary, in some instances because they were unexpected, and when they are of a magnitude that would result in a material impact on the utility's financial

[1] This dissent follows and relies on the same analysis and discussion as my dissent in Docket No. E-7, Sub 1214. Rather than require a reader to switch back and forth between text in that docket and in this one I have chosen to repeat and restate the same text here, modified of course where there are differences between the facts in the two dockets.

position in the absence of an ability to recover those costs from revenues in future periods. In applying this test the Commission has disfavored deferral treatment for expenditures that are planned or whose timing and amount are under the control of the utility. In this instance the record is clear that the costs for which deferral accounting treatment is requested are among a larger group of ongoing programs to modernize and upgrade DEP's transmission and distribution systems, many that commenced well before deferral accounting was requested in this case, all completely under the Company's control, and, none that, singly or in combination, present any significant threat to the utility's financial condition or its ability to earn its allowed rate of return.

Because deferral accounting is a departure from the basic ratemaking structure set forth in N.C.G.S. § 62-133(a)-(c), one must consider the Supreme Court's recent discussion in *Stein*. There the Court set forth four factors governing the Commission's reliance upon its authority under N.C.G.S. § 62-133(d) to supplement, modify, or depart from the basic ratemaking structure established in §§ 62-133(a)-(c). The four factors identified by the Court in its opinion are essentially a restatement of the Commission's traditional two-prong test for accounting deferrals:

> [W]e hold that the Commission may employ N.C.G.S. § 62-133(d) in situations involving (1) unusual, extraordinary, or complex circumstances that are not adequately addressed in the traditional ratemaking procedures set out in N.C.G.S. § 62-133; (2) in which the Commission reasonably concludes that these circumstances justify a departure from the ordinary ratemaking standards set out in N.C.G.S. § 62-133; (3) determines that a consideration of these "other facts" is necessary to allow the Commission to fix rates that are just and reasonable to both the utility and its customers; and (4) makes sufficient findings of fact and conclusions of law supported by substantial evidence in light of the whole record explaining why a divergence from the usual ratemaking standards would be appropriate and why the approach that the Commission has adopted would be just and reasonable to both utilities and their customers.

Stein, 375 N.C. at 926,851 S.E.2d at 273.

The record in this case plainly establishes that DEP does not need accounting deferral treatment to enable it to undertake and move ahead with its grid improvement initiatives (the Grid Improvement Plan or, sometimes, GIP). Public Staff witnesses testified that at the time of this general rate case and without any inducement or protection under a deferral accounting order the Company had already commenced work on thirteen of the GIP programs, that it spent about $38 million on those programs during 2018, and that it had spent another $164 million during 2019.[2] Tr. vol. 57, 378. During the update period of March through May 2020, DEP completed and placed in service another

[2] Except where otherwise noted, all figures are on a total system basis.

$52.8 million of investments in the various GIP programs.[3] Tr. vol. 16, 61. In fact DEP's own evidence was that spending on the self-optimizing grid program was outpacing its staff's ability to implement attendant computer programming changes needed to enable complete functionality of those investments, leading to delays in full implementation of some of the system upgrades. Tr. vol. 16 217-*8; see also* Commission Opinion at 135*.* Given these facts I am compelled to conclude that the GIP investments are quite far from being extraordinary, unusual, or unanticipated; they are instead well-thought out, planned, and executed upgrades and improvements to enhance the performance and the reliability of the Company's transmission and distribution systems. Maintaining, protecting, adapting, and enhancing reliability and performance of the electric grid are core obligations of any electric utility.

The Company contends that each of these investments, and those it wishes to make in the future, are necessary and indeed essential to respond to changes and challenges arising from such things as the deployment of distributed generation and other new grid-edge technologies and from increasing security concerns about cyberattacks on businesses and infrastructure such as the electrical grid. The fact that these improvements may be sound and even necessary does not, however, meet the Commission's standard for deferral treatment. The Company attempted to distinguish its GIP investments from other ongoing spending to upgrade equipment and facilities with newer, more efficient and effective replacements by relying on seven so-called "megatrends." These megatrends, however, are nothing more than general features of North Carolina's evolving demography and economy or else they arise from technological innovations that are affecting many sectors of modern life and do not uniquely affect the electric power industry. They have been at work for many years and are neither accidental, sudden, nor unforeseen. The difficulty with using these megatrends to justify special ratemaking treatment for the Company's GIP spending is that the argument simply proves far too much. Virtually every aspect of the Company's traditional model is being affected in some way by one or more of these megatrends. If the megatrends justify special ratemaking treatment for the eight specific GIP programs singled out in the Second Partial Stipulation, then they could justify similar treatment for all other portions of the Grid Improvement Plan and, for that matter, virtually every new investment the Company wishes to undertake.

Rather than being extraordinary or unusual I would find DEP's GIP programs to be more analogous to the automated meter reading (AMR) installations for which Carolina Water Service of North Carolina (CWSNC) sought deferral accounting in Docket No. W-354, Sub 364. Both involve the deployment of new technologies that promise substantial efficiencies and new capabilities for the utilities and resulting benefits for customers. In the CWSNC Order the Commission found that CWSNC's meter replacements had been on-going for several years and were anticipated to extend several more years into the future. In that case as in this one, the utility requested deferral

[3] This total of approximately $255 million spent over a period of approximately two and one-half years *without* the benefit of any deferral accounting treatment should be compared to the approximately $400 in GIP program expenditures over the two and one-half years from June 2020 through December 2022 for which the Commission finds deferral treatment to be necessary and appropriate.

accounting to mitigate the effect of regulatory lag on earned returns. The Commission rejected CWSNC's request, noting that the timing of meter replacements was entirely within the control of the Company. The fact that CWSNC's AMR investments spanned many years contributed to the Commission's determination that the investments were part of the regular business of adapting and updating the utility's systems to meet the most up-to-date standards and technologies. The fact that CWSNC sought to adopt a new technology and realize significant system benefits enabled by that new technology did not suffice to justify deferral accounting treatment. The DEP investments presently before the Commission also span many years, some programs starting as early as 2018 and some extending beyond 2022, based on DEP's cost-benefit analyses.[4] Several of them, such as the replacement of oil-filled hydraulic reclosers with remotely operated digital reclosing devices, the replacement of single-use fuses with automated reset fuses, and the replacement of electromechanical relays with remotely operated digital relays are virtually indistinguishable in substance from CWSNC's replacement of manually read water meters with AMR meters.[5]

In this instance several parties who support the Company's deferral accounting request, notably the Public staff, rely heavily, in fact almost entirely, on inferences they draw from the Commission's Sub 1146 Order. In that case DEC petitioned for creation of an annual revenue rider, or alternatively, to obtain deferral accounting treatment for a set of grid modernization programs it then referred to as Power Forward.[6] In its Sub 1146 Order the Commission found that DEC failed to show that Power Forward costs qualified for deferral accounting treatment. The Sub 1146 Order stated:

> [T]he Commission finds that DEC has not satisfied the criteria for deferral accounting. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude,

[4] Indeed, the Company's existing DSDR assets and functionality, which will be converted to operate in conservation mode at an estimated cost of approximately $10 million, were put into service several years prior to 2018, and the Company is already recovering the costs of the DSDR system through its DSM/EE rider. I am just not persuaded that the Company requires the benefits of accounting deferral treatment in order to make this conversion of an existing system to operate in a different modality.

[5] One of the eight GIP programs included in the Second Partial Stipulation involves cybersecurity. As the Commission's opinion notes, DEP witness Oliver testified that these elements of the GIP are essentially the same as those DEP has been funding in the past, only the amount of spending will be increased. Consolidated Tr. vol. 5, 39. As to those programs I also note that the Company has obtained an order from FERC permitting it to aggregate its expenditures into a single composite project eligible for AFUDC treatment, thereby allowing the Company to continue to accrue AFUDC until the last component element of its cybersecurity project is placed into service. FERC Docket No. AC19-75 (Dec. 19, 2019). It is not at all clear how this treatment relates to the deferral accounting treatment requested in this case or why if AFUDC treatment is available for these cybersecurity programs there would be any need for deferral accounting treatment for the cybersecurity programs at all.

[6] The specific programs for which deferral accounting treatment is sought in this case is a subset of the larger set of what DEP refers to as its Grid Improvement Plan, which in turn is itself a substantially modified version — both in scope and magnitude and as to its elements — of DEP's and DEC's earlier Power Forward initiative.

> to be considered for deferral. Second, the utility has to show that the effect of not deferring such cost items would significantly affect the utility's earned returns on common equity. Although it was uncontested by any party that DEC's planned Power Forward spend is extraordinary in magnitude, the Commission is unpersuaded that the entirety of Power Forward programs as proposed are unique or extraordinary. Assuming arguendo that all Power Forward programs as proposed were found to be unique and extraordinary, thus meeting the threshold criteria for consideration of deferral accounting, DEC failed to show that the effect of not deferring Power Forward costs would significantly affect its earned returns on common equity.

Sub 1146 Order, at 148.

The Commission further directed DEC to collaborate with stakeholders to address the myriad issues that had been raised about Power Forward in that rate case and also stated:

> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, *with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case*, the Commission authorizes expedited consideration, and *to the extent permissible*, reliance on leniency in imposing the "extraordinary expenditure" test.

Id., at 149 (emphasis added).

Public Staff witness Maness interpreted the Sub 1146 Order to mean that the Commission is prepared to show leniency as to the financial impact of the Company's request in the instant rate case.[7] That interpretation was not the Commission's intent and it does not comport with the actual language used by the Commission. Rather, the quoted language from the Sub 1146 Order refers to a scenario that did not occur, one in which DEC incurred grid modernization costs before the test year in the current case and requested deferral treatment for those costs in the interim period and outside the parameters of a general rate case. Had that occurred, the Commission was prepared to consider the request in an expedited fashion, outside a general rate case, and was prepared to be lenient in imposing the extraordinary expenditure test, especially if DEC's collaboration with the parties had produced consensus as to the programs whose costs would be deferred. That is simply not the situation now presented to the Commission.

[7] Strictly speaking, the so-called "leniency" language in the Commission's Sub 1146 Order applies to DEC only and not to DEP. No similar language was included in DEP's last general rate case order in Docket No. E-2, Sub 1142. All parties have, however, simply assumed that the Commission's language in the Sub 1146 Order should be treated as equally applicable to DEP. In its order in Docket No. E-2, Sub 1142, the Commission was silent on the matter of the future ratemaking treatment of expenditures on programs such as Power Forward or GIP.

Moreover, the language from the Sub 1146 Order relied upon by the Public Staff was directed to the first prong of the Commission's deferral accounting standard – that the expenditures be unusual or extraordinary in type and magnitude – and not to the second prong of that standard. On that issue the pertinent language from the Sub 1146 Order is the following:

> With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside of the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during a test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside a test year *and meet the test of economic harm,* the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs.

Id. (emphasis added).

In his direct testimony Public Staff witness Maness stated that the Public Staff would not object if the Commission determined that the ROE impacts from a narrower set of GIP programs fall within the range of leniency that the Commission intended in the Sub 1146 Order. Tr. vol. 15, 1600-01. Strikingly, however, in response to questions from Commissioner Brown-Bland, witness Maness confessed that absent the quoted language from the Sub 1146 Order he could not conclude that the GIP investments proposed for deferral treatment in the Second Partial Stipulation would meet the second, financial impact prong of the Commission's standard. Consolidated Tr. vol. 7, 32; *see also* Commission Opinion at 122.[8] The GIP programs included in the Second Partial Stipulation are very dramatically scaled back from the group of programs that constituted the original Power Forward initiative. If, as the Commission found in the Sub 1146 Order, the multi-billion dollars of proposed Power Forward spending was insufficient to affect in a significant way the utility's potential to earn its authorized return on common equity, then I cannot conceive how a contrary finding could be supported as to the GIP programs covered in the Second Partial Stipulation based on the evidence in this proceeding. Moreover, the Company's own witnesses explained that in the absence of deferral accounting treatment, the Company had other ways to manage the financial impact of the proposed GIP expenditures. DEP witness Oliver confirmed that if the Commission did not grant deferral accounting treatment for the proposed GIP programs, the Company nevertheless would continue to implement them, managing and adjusting to

[8] Even if the Sub 1146 Order were interpreted such that "leniency" is taken to refer to both prongs of the deferral standard, not just the "extraordinary expenditure" prong, it should be noted that the Commission qualified leniency with the phrase "to the extent permissible." The outer boundaries of what is "permissible" are not, and likely could not be, established with certainty. But a virtual abandonment of the requirement that the utility show substantial financial harm is not, I think, within those boundaries. In this regard I note that N.C.G.S. § 62-133(b)(1)a authorizes the Commission to approve inclusion of construction work in progress in rate base, a mechanism to address regulatory lag similar in some ways to deferral accounting, when the Commission finds such use to be in the public interest "and necessary to the financial stability of the utility in question."

accommodate available resources and timetables in order to do so. Consolidated Tr. vol. 6, 56.

Leaving aside the Commission's two-prong test for deferral treatment and the Supreme Court's *Stein* factors defining the Commission's authority to depart from traditional ratemaking principles, there are other features of the Second Partial Stipulation's provisions dealing with GIP programs that I find unsettling. One involves what exactly it is that the parties are asking from the Commission. Deferral accounting treatment for expenditures made in connection with specific GIP programs is certainly being sought, but there is also something more. During the consolidated portion of the hearing DEC witness Jane McManeus testified that it is important for the Commission to make clear that the Commission believes the GIP programs are appropriate undertakings and that the costs of such program can ultimately be recovered from customers, assuming they are found to be reasonable in amount. Consolidated Tr. vol. 9, 24. DEP witness Kim Smith testified that she agreed with witness McManeus. *Id.* at 33. To that end the Second Partial Stipulation contains the following paragraph:

> The Stipulating Parties' agreement regarding deferral treatment of GIP costs constitutes only approval of the decision to incur GIP program costs. The Public Staff reserves the right to review costs for reasonableness and prudence.

Second Partial Stipulation § Ill.D*.*

Under questioning from Commissioners neither the Company nor the Public Staff witnesses were able to give completely clear meaning to this provision, seeming to contend that acceptance of this provision commits the Commission to allowing cost recovery for GIP program expenditures in future rate cases while at the same time preserving the Commission's full review of GIP spending under the traditional "prudence" standard. As I interpret it, the Company is seeking prior Commission approval of a list of loosely related programs, a practice this Commission seldom follows outside certificate of public convenience and necessity proceedings.[9] Some of those programs involve primarily operational and business process changes, such as the Integrated Systems Operations Plan, while others involve investments in new hardware and physical infrastructure. The Company did not articulate any set of unifying principles – aside from referring to the so-called "megatrends" – that bring these disparate programs into a single integrated whole. The proposed bifurcated review, which is what I believe the quoted provision is attempting to accomplish, deprives the Commission of the ability at the time when all costs have been incurred and all benefits have been have realized to judge whether or not the investment was warranted in the first instance. Although the Second Partial Stipulation contemplates ongoing review of GIP program spending by the Public

[9] Indeed, as to those elements of the GIP that involve investment in utility plant and equipment, as opposed to expenditures made on such things as planning, operational design and operating management of the grid, if those investments are indeed so extraordinary and unusual as is contended, one may well ask why they are not subject to the certificate of public convenience and necessity requirement set forth in N.C.G.S. § 62-110(a), which requires a certificate before construction or operation of "any public utility plant or system," except where such construction or operation occurs in the "ordinary course of business."

Staff, it does not set forth any clear or measurable performance goals or targets that must be met in order ultimately for cost recovery to be allowed. According to the Second Partial Stipulation the Public Staff's review will include an evaluation of actual benefits realized compared to anticipated or expected benefits. What will be the way forward if the Public Staff should conclude that expected benefits failed to materialize in any significant degree or were wholly or very largely offset by unexpected or additional costs? In such a case will the quoted provision from the Second Partial Stipulation permit or not permit the determination that cost recovery should be denied altogether? Unlike a majority of the Commission, I do not believe that an aggregate spending cap on the amount of expenditures for which deferral treatment is allowed adequately substitutes for clear and measurable performance goals or targets that must be met in order for cost recovery to be allowed.[10]

A second unsettling feature of the Second Partial Stipulation's treatment of the GIP programs involves the increasing tendency for regulated utilities to attempt to string together a series of small-scale investments in order to craft some composite whole that can be offered up for deferral accounting treatment. The evolution first from Power Forward, then to the Grid Improvement Plan, then to a series of multiple, only partially overlapping, settlements between DEP and various individual parties to this proceeding about which GIP programs those parties would support, finally culminating in the Second Partial Stipulation with the Public Staff is a good illustration of the potential problems with this approach to solve the problem of regulatory lag.

In a recent general rate case involving Aqua North Carolina, Inc. (Aqua), Public Staff witnesses expressed reservations about a deferral accounting request that involved the aggregation of many unrelated projects. *See* Joint Testimony of Windley E. Henry and Charles M. Junes dated May 26, 2020, in Docket No. W-218, Sub 526. These witnesses testified that Aqua's deferral request was based on "the novel argument that the projects and related costs for which it seeks deferral accounting treatment should be considered not on an individual basis, but in the aggregate." I believe the same could be said of DEP's GIP request in this case. I am concerned with the large number and variety of programs that DEP has included under the GIP umbrella, with cost estimates that could vary by as much as 30 percent, and that contains many investment types that overlap with customary maintenance, repair, and upgrade expenditures. It will, I believe, become increasingly difficult for the Commission to apply the "extraordinary" or "unusual" prong of its established deferral accounting standard with any degree of integrity or consistency if this practice of aggregating small programs and expenditures becomes well established, especially if, as occurred in this case, that aggregate is arrived at by a process of negotiation and settlement among contending stakeholders.

A third feature that gives me pause concerns the future rate impacts of the Commission's approval of the Second Partial Stipulation. It is true that the decision to

[10] The "loose approval" treatment afforded here for the proposed GIP programs can be contrasted with the carefully structured provisions in N.C.G.S. § 62-110.1 governing certificates of public convenience and necessity for new generating facilities, which include several clauses authorizing the Commission to modify, revoke, or cancel a previously granted CPCN.

approve deferral accounting treatment for the GIP program expenditures included in the Second Partial Stipulation has no impact on the rates established in the present case. I cannot ignore, however, the implications of this request for future rate cases. The Company supports its case for the GIP investments by offering cost-benefit analyses that, the Company contends, show strong positive economic benefits from those investments. These analyses covered only some components and subprograms within the larger GIP effort, and they were strongly criticized by several intervenor witnesses as being based on studies or data that were out-of-date, were not well-tailored to the demographics and economy of North Carolina, or were otherwise deficient or flawed in various respects. Even if all those criticisms are valid, it nonetheless remains true that the Company and the contending intervenor adversaries did not disagree on either the directionality or the order of magnitude of one unmistakable feature of the Company's cost-benefit studies. The economic benefits disclosed by those studies center on improvements to service reliability, and they overwhelmingly flow to the benefit of the industrial and commercial customer classes. *See* Commission Opinion at 134*.* Yet based on the Company's analysis filed in this case the revenue requirement and resulting rate impact from the GIP programs will fall most heavily on the residential customer class. *See* Commission Opinion at 122*.* For me this is an important point.[11]

Witnesses for the Company and supporters of the GIP contended that the Commission should keep separate the present question, which is whether to grant permission to proceed with the GIP investments and grant deferral accounting treatment, from the question in future rate cases concerning how GIP program costs should be assigned to the different customer classes and, accordingly, reflected in rates. In the face of the extensive evidence presented in this case concerning problems of affordability of electric service, especially for low-income and unemployed North Carolinians and for many small businesses bearing the burden of a year of COVID-19 disruptions, I simply cannot perform this feat. If complications concerning the differential future rate impacts on different customer classes are staring at us from the end of the road, I am not comfortable pre-approving the GIP programs and granting them special ratemaking treatment without fully considering how the Commission will manage those complications when they materialize in future rate cases. The better approach would be to evaluate actual GIP expenditures made by the Company and actual results achieved for customers in the context of all other issues and decisions that culminate in the setting of just and reasonable rates in a future general rate case. While the Commission's decision to place a cap on the total GIP expenditures eligible for accounting deferral is a useful step, it is an inadequate substitute for the kinds of tools the Commission must have in order to

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[11] Certain witnesses contended that it is not appropriate to consider the proportionality of the assignment of costs relative to the realization of benefits among the various rate classes. I commend to those witnesses Part I, Chapter 5 of Professor Bonbright's treatise, *Principles of Public Utility Regulation* (1960), where he discusses the use of the concepts of "value" and "benefit" in ratemaking. Summarizing the different theories and ways in which those concepts come into play, he observes" "…[I]n actual rate cases the cost [of service] principle is always given modified interpretation which, while not converting it into a value principle, takes indirect account of the effectiveness of the cost incurrence in contributing to the benefit of the consumers." *Id.* at 91.

properly grant pre-approval of the kinds of forward-looking expenditures such as the Company's proposed GIP investments.

Although in the end I dissent from the Commission's decision to grant deferral accounting treatment for elements of the proposed GIP, I am nonetheless conflicted about doing so. Increasingly, our present statutes governing ratemaking are proving to be poorly suited to address the types of investments that utilities are making and must continue to make in order to transition the electricity grid to the new world of distributed generation from renewables, non-wires solutions to grid reliability and capacity issues, and the two-way power flows that result from these first two trends, not to mention looming electrification of the transportation and real estate sectors and new challenges to grid reliability and resiliency due to cyberattacks and severe weather events. The fundamental paradigm by which rates are derived from examination of historic expenditures was adequate for a time when the electricity system was more stable and when major capital investments were largely centered on the addition of new centralized generating plants built to accommodate increases in aggregate system load. That paradigm does not work well now.

Even under the traditional ratemaking paradigm the General Assembly has shown an understanding of the need for tools that would enable what I would call "forward-looking" or, alternatively, "rapid response" ratemaking treatment in instances involving major capital expenditures or concerns about regulatory lag. In 2013 the General Assembly enacted N.C.G.S. § 62-133.12 to alleviate the effects of regulatory lag by allowing for recovery outside a general rate case of some portion of incremental depreciation expense and capital costs for eligible water and wastewater infrastructure projects that are placed into service between general rate cases. I believe the same recognition underpins N.C.G.S. § §62-133(b)(1)a and (b)(1)b, which establish the Commission's authority, under the circumstances and conditions spelled out in those statutes, to include in rate base construction work in progress, and also N.C.G.S. § 62- 110.7, which governs advance review and approval of nuclear power plant development. To date, however, for investments of the type exemplified by the GIP programs, no such special statutory treatment has been enacted, and thus the Commission is left to operate within the limits established by N.C.G.S. § 62-133(a)-(c), supplemented by § 62-133(d) as interpreted by the Supreme Court in *Stein.*

I wholeheartedly support efforts to change the existing ratemaking paradigm embodied in Chapter 62, and I was encouraged by the progress made in the consideration of SB 559 in the 2019-2020 session of the General Assembly. Though that legislation ultimately was not enacted, it will not be the last such effort. Recommendations coming from stakeholder working groups convened to flesh out the Clean Energy Plan developed in response to Executive Order 80 contain a number of options and possible changes to the General Statutes that could, if adopted, enable the Commission better to manage approval, oversight, and cost recovery for initiatives such as DEP's Grid Improvement

Plan.[12] Unfortunately, though, for now we must decide proceedings before us following the statutes we have. The Commission's decision is ultimately based not on substantial evidence that is material and sufficient under current law and precedent but instead on a wish and a hope – a wish that the Commission had the kind of authority I believe is essential for the future and a hope that the General Assembly will, even if after the fact as far as the present proceeding goes, take action that validates the policy rationale for the decision in this case. I share both that wish and hope, but I am constrained by the tools that we have been given by the General Assembly until they are changed.

I differ from the majority in that I do not believe a partial settlement of disputed issues, even more so an agreement by fewer than all parties and in circumstances where different settling parties agree on different provisions for settlement, can substitute for the Commission's lack of authority to engage in "forward looking" ratemaking, or that it can override or displace the Commission's existing standard for deferral accounting treatment, or that it can rectify the deficiencies in the evidence submitted to the Commission under its traditional test for an accounting deferral order. While settlements are certainly to be encouraged, I believe the Commissions' deference to the Second Partial Stipulation in this instance fails to comply with the requirement that the Commission exercise its own independent judgment with respect to the matters embraced in the settlement. This is especially troubling in that the settlement overrides a Commission standard that is to be used sparingly and whose use is to be considered an exception to general ratemaking principles. If litigating parties come to know and understand that by a settlement they can circumvent the Commission's standard, then what will be left of the notions of "sparingly" or "exceptional"? With respect to the Commission's decision granting deferral accounting treatment for certain of the Company's GIP expenditures I must therefore respectfully dissent.

II. Coal Ash Disposal and Groundwater Remediation Costs

Though I endorse much of the Commission's discussion of the proposed settlement relating to coal ash disposal and remediation costs, I cannot go the full distance. Pending before the Commission now are two matters only – first, a decision establishing rates in this proceeding and second, a decision on remand from the Supreme Court in Docket No. E-2, Sub 1142. I agree with the Commission majority that those portions of the CCR Settlement that address the two pending matters are appropriate and would produce rates that are fair and reasonable to the Company and to ratepayers. In arriving at this conclusion I have relied on the combined effect of the settlement of the case on remand and the settlement of the current proceeding. Considering them separately and individually, however, I would not reach the same result. For reasons discussed in my dissenting opinion in Docket No. E-2, Sub 1142 I do not consider the result in that case to be one that yielded just and reasonable rates, and the proposed CCR Settlement would reaffirm and leave unchanged that result. At the same time, however, the CCR Settlement would impose a greater reduction in the cost recovery

[12] See North Carolina Energy Regulatory Process – In Fulfillment of the North Carolina Clean Energy Plan B-1 Recommendation, December 22, 2020 Summary Report and Compilation of Outputs (https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/2020-NERP-Final-Report.pdf).

request for ash basin closure and groundwater remediation expenditures in this case than I was prepared to impose, based upon the evidence offered in this case and the specific facts concerning the particular expenditures for which cost recovery is sought in this case. Because the combined effect of the settlement in this case and the settlement of the case on remand in Docket No. E-2, Sub 1142 closely approximates, for both the Company and for ratepayers, the combined result I would have reached, I support the CCR Settlement as to the two matters now before the Commission for disposition.

I am unclear as to exactly what position the Commission is taking with respect to the forward-looking provisions of the CCR Settlement. *See* Commission Opinion, Findings of Fact 20, 21, and 23. Aside from authorizing the Company to continue to defer ash basin closure and remediation expenditures in the same manner as was approved for the costs in this case and those in Docket No. E-2, Sub 1142, at this point I would take no position on those portions of the CCR Settlement that speak to the treatment of ash basin closure and groundwater remediation costs in future general rate cases. Those matters are not now at issue and thus are not before the Commission. Whether the financial terms the settling parties propose be applied to cost recovery requests in future rate cases will produce just and reasonable rates is, I believe, a question that can only be decided when the Commission has before it all the facts and circumstances of those future cases.

Finally, while I join in the Commission's directive, *see* Commission Opinion at 68-69, that the Company consider in its next general rate case the option of including in base rates a normalized allowance for ongoing coal ash expenditures, I would also have been prepared to go further and adopt such a cost recovery mechanism in the present case for all or some of the company's ongoing costs. When this mechanism was first suggested by the Company's affiliate, Duke Energy Carolinas, in its general rate case in Docket No. E-7, Sub 1146, it was rejected by the Commission. Two fundamental developments since that time have made the option viable and even, in my view, preferable to what the Commission and the parties have called the "spend-defer-recover" method employed to date. First, the Company's settlement with the Department of Environmental Quality means that from this point the nature and scope of the tasks that the Company will be required to perform in order to close the remaining ash impoundments and remediate detected groundwater contamination are no longer subject to regulatory uncertainty and litigation. They can be predicted and planned with a much greater degree of accuracy than was possible in 2017. Second, the Company has now substantially completed or is well advanced toward completing impoundment dewatering, ash excavation and other closure activities at its Sutton and Asheville facilities and has thereby gained valuable experience in forecasting the costs it may reasonably expect to incur to perform various closure activities. Because this cost recovery option would provide the Company consistent, predictable current cash flow to fund impoundment closure activities, not requiring it to tap its credit facilities or use shareholder capital, and because it would do so at lower cost to ratepayers, I believe it to be the superior method for achieving just and reasonable rates.

III. Cost Allocation Matters

Briefly, I note that my views on the appropriateness of using the single coincident peak method for allocating among customer classes the demand portion of production costs and of using the minimum system method for allocating a portion of distribution system costs on a per customer basis remain unchanged from my dissents in Docket Nos. E-2, Sub 1142 and E-7, Sub 1146. I believe these two cost allocation methodologies are flawed, and in the case of the so-called “minimum system” method they are increasingly being abandoned by regulatory commissions in favor of the “basic customer charge” method. In this case the Company was unable to produce any new, different, or more persuasive reasons for me to reconsider my prior positions. I am, however, hopeful that the two stakeholder forums initiated by the Commission’s decision in this case, one intended to take a comprehensive review of matters of rate design and the other dealing with problems of affordability, will permit a more extensive debate about how these flawed cost allocation methods help drive many of the problems that exist in current customer classifications and class rate designs and with respect to the affordability of service for low-income residential customers.

For the foregoing reasons and with respect to the issues discussed in this opinion, I dissent.

/s/ Commissioner Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

Commissioner Floyd B. McKissick, Jr., dissenting in part, and concurring, with an explanation:

Deferral of Grid Modernization Expenses

The majority has accepted the Second Partial Stipulation as it relates to eight separate projects which they are now collectively referring to as being part of a Grid Modernization Program. I must dissent on this issue. In my opinion, these projects fail to satisfy the four factors identified by the Supreme Court in *Stein*, which are substantially the same as the two-pronged test historically applied by the Commission for accounting deferrals. The Commission's acceptance of the Second Partial Stipulation in light of these circumstances has the potential to incentivize applicants in future cases where deferral treatment is sought to use the give and take of compromise to seek the deferral treatment of projects which would not otherwise meet or satisfy standards of the court or of this Commission. In addition, the Company commenced substantial work pursuant to its Grid Modernization Program before it sought deferral accounting treatment in this proceeding, and testimony provided by the Company's witnesses during the hearing clearly and unambiguously expressed an intent on the Company's behalf to carry out its Grid Modernization Program regardless of whether deferral accounting treatment was granted by the Commission in this proceeding.

Coal Ash Disposal

Concurrence with Explanation

After conducting a critical review of the CCR Settlement, I am persuaded that the give and take of the compromise process has resulted in an agreement between the parties to the stipulation, those parties being DEP, the Public Staff, the North Carolina Attorney General's Office, and the Sierra Club, to the issues set forth and agreed upon in the CCR Settlement. It is I believe uncontroverted, but nonetheless worth stating, that this agreement cannot legally bind other parties or intervenors in the future through the year 2030 that were not parties to the agreement. Therefore, intervenors in the future that were not parties to the CCR Settlement would be free to raise issues or contentions they deem relevant and appropriate relating to these issues. Likewise, future Commissions would have a duty and responsibility to hear and receive evidence on the issues at an appropriate time, including evidence relating to the issues agreed upon by the stipulating parties in the CCR Settlement. This includes issues related to the treatment of coal ash basin closures and remediation cost in future general rate cases.

As noted in the Commission's Order, the CCR Settlement does not involve a contemporaneous cost recovery mechanism which could be of substantial benefit to ratepayers as well as to DEP. I am of the opinion that a properly structured cost recovery mechanism would be far preferable to the "spend-defer-recover" method in the CCR Settlement Agreement.

/s/ Commissioner Floyd B. McKissick, Jr.
Commissioner Floyd B. McKissick, Jr.